California Energy Commission

STAFF FINAL REPORT

2011 NATURAL GAS MARKET ASSESSMENT: OUTLOOK

In Support of the *2012 Integrated Energy Policy Report Update*

CALIFORNIA
ENERGY COMMISSION

Edmund G. Brown Jr., Governor

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CALIFORNIA ENERGY COMMISSION

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The natural gas market is part of a worldwide energy commodities market that interacts in complex ways with petroleum, coal, and electricity markets. This report's estimates of future natural gas market activity and prices are based on representations of the interactions of these worldwide energy markets in a computer model. Staff has relied on the experience and expertise of Kenneth B. Medlock III, Ph.D., for both model relationships and input assumptions about key drivers of market activity, especially for activity outside California. Dr. Medlock is the James A. Baker III and Susan G. Baker Fellow in Energy and Resource Economics and Deputy Director of the Energy Forum of James A. Baker III Institute for Public Policy of Rice University in Houston, Texas. Staff also received assistance from Catherine M. Elder, M.P.P., of the Aspen Environmental Group, on analyzing inputs and outputs of the natural gas model and evaluating impacts of the San Bruno explosion.

Since its *2007 Natural Gas Market Assessment*, the California Energy Commission has experienced significant and ongoing reductions in the number of staff members with expertise in natural gas markets, so much so that staff was unable to conduct a model-based natural gas market assessment in support of the *2009 Integrated Energy Policy Report*. With this report, staff has been able to include modeling among its analytic techniques. Staff members acknowledge the direction and support they have received during this long transition from former Executive Director Melissa Jones, Deputy Director Sylvia Bender, and Catherine Elder, M.P.P., Senior Associate Aspen Environmental Group.

Staff also acknowledges the interest, direction, and support it has received from both Chair Robert Weisenmiller, Ph.D., and Commissioner Carla Peterman of the Energy Commission's Electricity and Natural Gas Committee.

Staff thanks interested parties for their participation at workshops and for comments on staff's workshop materials, presentations, and proposed study design, including Pacific Gas and Electric Company, Sempra Energy Utilities, Western States Petroleum Association, and Southern California Edison Company.

Lastly, the newer members of the natural gas staff gratefully acknowledge the expertise, leadership, and mentoring efforts of both longtime staff members William Wood and Leon D. Brathwaite.

PREFACE

State government has an essential role to ensure that a reliable supply of energy is provided consistent with protection of public health and safety, promotion of the general welfare, maintenance of a sound economy, conservation of resources, and preservation of environmental quality (Public Resources Code Section 25300[b]). To perform this role, state government needs a complete understanding of the operation of energy markets, including electricity, natural gas, petroleum, and alternative energy sources, to enable it to respond to possible shortages, price shocks, oversupplies, or other disruptions (PRC Section 25300[c]). The California Energy Commission's timely reporting, assessment, forecasting, and data collection activities are essential to serve the information and policy development needs of the Governor, the Legislature, public agencies, market participants, and the public (PRC Section 25300[c]).

This report describes the methods, assumptions, and results of staff's analysis of plausible future natural gas market conditions using the World Gas Trade Model. A companion staff report, *2011 Natural Gas Market Assessment: Trends*, provides an overview of major natural gas market trends and issues facing the state, including, but not limited to, supply, demand, pricing, reliability, efficiency, and impacts on public health and safety, the economy, resources, and the environment (PRC 25302[a]).

ABSTRACT

The *2011 Natural Gas Market Assessment: Outlook* is produced as part of the California Energy Commission's *2012 Integrated Energy Policy Report Update*. In this report California Energy Commission staff, in collaboration with industry experts from Rice University and elsewhere, has developed future planning cases illustrating natural gas prices and quantities demanded under a variety of assumptions.

Key to this effort is staff's acknowledgement that it is impossible to predict the precise state of the world 6 months or 10 years hence. Instead, staff has produced estimates that are "conditional" on the input assumptions that underlie each case. These cases can be broadly categorized by the kinds of conditions they are meant to capture. The California Energy Commission Reference Case presents the future state of the natural gas market under conditions that can best be described as "business as usual." This case posits increasing production from domestic shale reserves and a return to the long-run economic growth path experienced by the United States for the last 20 years. The second set of cases examine national and international drivers that may affect natural gas markets on a large scale and drive national and international natural gas prices and demand either higher or lower than the Reference Case. A third set of cases examines California-specific drivers that may drive demand for natural gas in California either higher or lower than the Reference Case assumes. The final set of cases were added based on stakeholder feedback and expand the range of plausible gas prices by examining the results from sustained high and low finding and development costs.

Keywords: Natural gas, shale, hydraulic fracturing, fracking, supply, demand, infrastructure, trading hub, border price, citygate, price, production, processing, pipelines, liquefied natural gas, LNG, regasification, maximum allowable operating pressure

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EXECUTIVE SUMMARY

It is the aim of this natural gas assessment to provide estimates and insights that are useful to California energy and environmental policy-making and implementation. However, this report does not to make accurate predictions of future natural gas market outcomes, but provides multiple plausible conditional estimates that explore potential vulnerabilities or opportunities California may face. Making accurate single-point forecasts of future gas prices and other market activities is not feasible. This is a necessary consequence of the gas market's high complexity, large menu of competing options for actions, and deep uncertainties about future conditions that are beyond one's control.

Worldwide natural gas markets, already linked to petroleum markets, have converged with electricity markets, a fact that multiplies the complexity of interactions among them. Concerns about greenhouse gas (GHG) emissions press for an even greater role for natural gas in serving transportation demand, either directly or indirectly via electrification. The menu of options available to society for dealing with energy and climate change issues is large and varied, including such seemingly disparate actions as building zero-net-energy homes to building new nuclear-powered generating plants. A zero-net-energy home produces as much energy as it consumes. The actual future state of various conditions that can significantly affect future natural gas markets is deeply uncertain (such as future emission reduction policies, future demand for gas-fired electric generation, and so forth). Even experts cannot agree on the future likelihood of such events.

These conditions of high complexity, many options for action, and deep uncertainty argue that market analysts move away from so-called "best guess" or "most likely" forecasts. However, policy-making and decision-making still often require some estimates of future market conditions, even in the face of great uncertainty. Building and running models to better understand the potential effect of the uncertainties on market outcomes thus can be very useful in helping to advise decision-making. This necessarily implies that some combination of scenario or sensitivity analysis would be useful, and that is the approach staff took in this assessment. Having multiple plausible "conditional estimates" of the future, which help explore what future natural gas market conditions might be, gives the potential user of such estimates more information about the conditional nature of the estimates. This knowledge helps the user understand the potential consequences of one's own use of a given estimate should the future turn out to be different. Having a better understanding of the uncertainties and their potential consequences can lead to more "robust" decisions—those having satisfactory consequences over a broad range of future conditions that cannot be accurately predicted or controlled.

Scope

This natural gas market assessment begins by examining recent trends in demand, supply, infrastructure, and price. The results of this trends analysis will be published as a separate staff report, soon to follow this natural gas market assessment. It will update the current trends analyses staff conducted for the *2009 Integrated Energy Policy Report*, which can be found at the California Energy Commission's website for that proceeding. An analysis of current trends identifies the underlying key drivers of the observed trends. The drivers may include economic, demographic, environmental, regulatory, and policy conditions. The current trends assessment report will also point out identified concerns or controversies that could affect the future states of key drivers, and staff's ability to predict them accurately. This examination of trends helps with understanding what might be plausible ranges of uncertainty for the future states of these key drivers, which guides the assumption changes in the case studies.

How the limitations of estimation techniques and modeling affect the development of this assessment's starting point case, the Energy Commission's Reference Case, and the changed cases are discussed in Chapter 2, as are the changes to input assumptions made in each case. Understanding the nature of and reasons for the specific input assumption changes is critical to interpreting the model outputs.

Chapter 3 presents the natural gas market modeling results for the cases staff developed in the September 2011 draft report, including volumes of gas demanded, the type and location of gas supply sources being produced, the use of pipeline capacity, and the resulting prices. Chapter 3 also discusses ongoing pipeline operational safety issues related to the 2010 San Bruno pipeline explosion, since these activities are more current and dynamic than other issues examined in this assessment. The model simulates wholesale market activity from wellhead production to the point where gas distribution utilities take control of the gas (at their *citygate*) for distribution to customers. More specifically, model results are presented by comparing and drawing insights from the different cases for each of the following areas:

- Price: Prices at major market hubs, such as the one at Henry Hub, are compared over time and across the United States.
- Supply: The quantities of natural gas produced within the United States, the amounts imported, and the amounts from shale deposits are compared.
- Infrastructure: The amount of new pipeline capacity that the model estimates to be built in response to economic conditions is compared.
- Demand: The amount of natural gas consumed by various end-use sectors, including for electric generation, is compared.

At the September 27, 2011, workshop staff acknowledged that the High CA Gas Demand and Low CA Gas Demand Cases had not been executed exactly as planned or as described in the draft report. Those cases have been rerun and the corrected results included in revised tables, figures, and text of Chapters 3 and 4 of this final report. Otherwise, Chapters 2, 3, and 4 remain essentially as they were in the staff draft report. Where typographic or other errors were found, they have been corrected.

Chapter 4 describes conditional estimates of gas prices to end users and discusses uncertainties that affect future values these prices may take. Retail distribution of the gas is not included in the model results, nor is the final retail price. This is a "post-processing" activity in which the components of distributions costs are estimated and added to the commodity and transportation costs delivered at the citygate. Just as the wholesale market modeled cases have varied outputs for gas commodity and transportation costs, so too can the significant costs associated with the distribution function vary, depending on what assumptions one makes about the future conditions that affect distribution costs. Uncertainties about aging infrastructure replacement, public safety, environmental mitigation, and climate change policy implementation contribute to the range of variation future end-use gas prices may take. This chapter also provides a current update of the 30-inch gas pipeline explosion that occurred in San Bruno, California, on September 9, 2010. The National Transportation and Safety Board identified a substandard and poorly welded section of the pipeline as the cause of the explosion. Since Pacific Gas and Electric could not find records for all pipelines, the California Public Utilities Commission (CPUC) ordered the utility to develop a plan for testing all the pipelines. The plan was extended to all the gas utilities in the State. The utilities submitted their plans to the CPUC on August 26, 2011. If the plans are approved by the CPUC as they have been submitted, they will cost more than $4.0 billion dollars to ratepayers.

Chapter 5 discusses the results of six new sensitivity studies which staff conducted after the September 27, 2011, joint *2011 Integrated Energy Policy Report* and Electricity and Natural Gas Committee workshop on the draft staff report. Written comments were requested and received by parties by October 10, 2011. In response to workshop and written comments, staff designed and conducted new sensitivity studies. Chapter 5 describes these sensitivities and compares their results to results of the original cases.

Additional appendices have been added to this final report in support of the new analyses and to respond further to public comments.

Highlights of Current Trends

On April 19, 2011, as part of the *2011 Integrated Energy Policy Report* proceeding, the Energy Commission staff held a workshop to discuss current trends in the natural gas industry that affect California. Staff received comments from several stakeholders and is developing a full report on current natural gas demand, supply, infrastructure, and price issues. Staff is providing a summary of the issues addressed in that report.

Demand Situation

- Over the past decade, the U.S. and California residential and commercial demands for gas remain flat, despite continued population growth.
- Price-responsive industrial sector demand exhibits a generally declining long-term trend, culminating in the current recession-driven downturn.
- Only power generation sector gas demand is increasing, although the recession's effect on electricity demand is also felt in demand for this generation fuel.

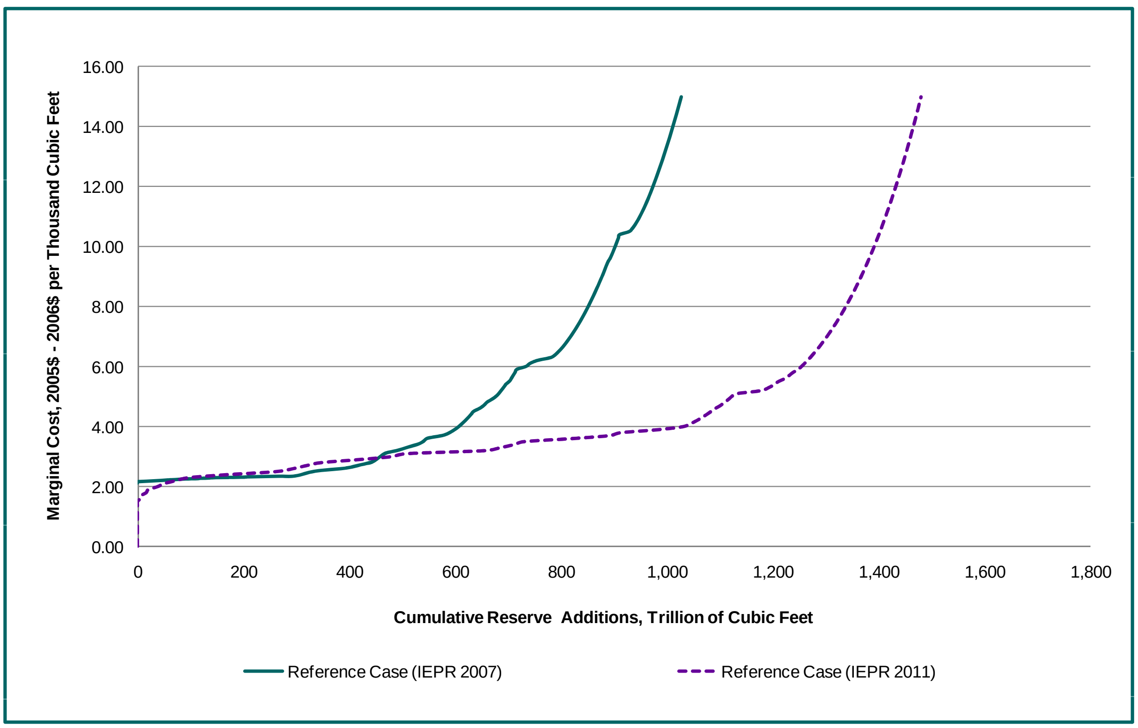
Gas Supply Situation

A variety of technological improvements are coming together:

- Three-dimensional and four-dimensional seismic exploration surveys improve the knowledge of what is underground, increasing potential reserves.
- Directional horizontal drilling increases access to underground resources, particularly in shale formations, both:
    - Improving the productive capability of natural gas-bearing formations.
    - Reducing uncertainty in potential resource estimates.
- Well completion and stimulation activities improve the effectiveness of extraction and lower the cost of producing gas from shale formations.
    - Instead of single-zone well completions, natural gas producers now perforate and stimulate multiple zones.
    - The stimulation process, known as hydraulic fracturing, allows greater natural gas flow to the wellbore, sometimes as much as a tenfold increase in initial production.

These improvements are changing the understanding of the underground resource and accessibility to it. **Figure ES-1** compares the current outlook for gas supply costs to the outlook in 2007.

Figure ES-1: Change in Outlook of Gas Supply Costs, 2011 vs. 2007



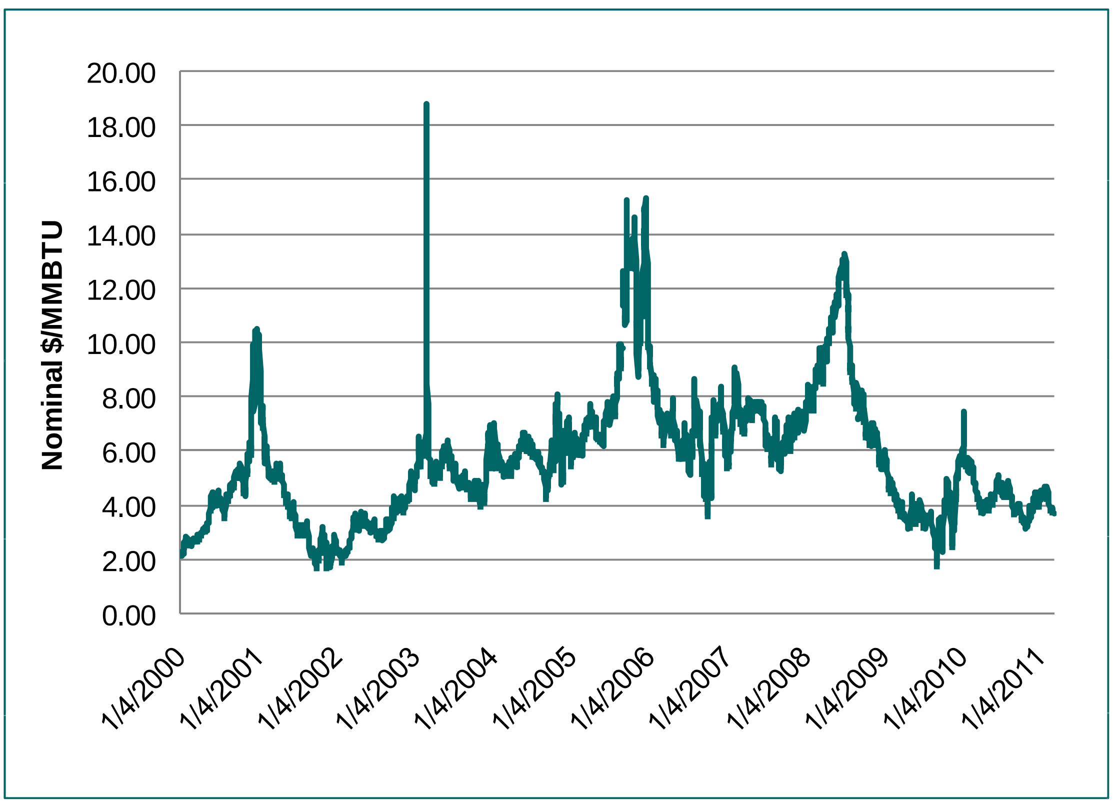
Source: Rice World Gas Trade Model and California Energy Commission staff analysis.

This radically different resource outlook shown in **Figure ES-1** reverses the future trends predicted in past forecasts, which had foreign supplies outcompeting increasingly expensive domestic supplies on price and being imported to the United States as liquefied natural gas (LNG). Spurred on by high oil and natural gas prices, increased levels of finding and development activities, technological innovations, and cost reductions through learning improvement have all resulted in this dramatic reassessment of the North American resource. For example, the outlook in 2007 was that about 700 trillion cubic feet (Tcf) of gas was economically recoverable at a real price of $6 (2005-6$), but that has now increased to about 1,250 Tcf—an almost 80 percent increase.

Gas Price Situation

Natural gas is a heavily traded market commodity characterized by inherent volatility. Over just the last decade, natural gas prices spiked several times (see **Figure ES-2**). The winter periods of 2000/2001 and 2003/2004 saw prices spike to $10 per million British thermal units (MMBtu) and $18/MMBtu, respectively. Cold weather, which increased demand and put upward pressure on price, triggered these spikes. In September 2005, hurricanes Katrina and Rita caused natural gas production in the Gulf Coast to be shut in. This situation lowered available supply and caused prices to spike over $15/MMBtu.

Figure ES-2: Henry Hub Daily Spot Market Natural Gas Prices



Source: http://intelligencepress.com.

Since late 2008, natural gas prices have trended lower, in the $4.50 to $5.00 range, and only once in 2009 did prices increase above $6.00. The lower prices following the 2008 price spike can be explained by two factors. First, the late-2008 economic recession reduced overall demand for natural gas; the industrial and power generation sectors declined more than other sectors. The lower natural gas demand had a negative effect on prices. Second, as described above, large amounts of shale gas are now technically and economically recoverable. This injection of shale gas into the market increased the supply of gas available to consumers and thus helped to lower the price of natural gas. Over the last year (April 2010 – April 2011), Henry Hub spot prices have averaged $4.15/MMBtu; this is mainly attributable to slow economic growth and the abundance of shale gas supplies.

Are Current Trends a Reliable Guide to the Future?

Might the trends being observed today continue into the future? Can the underlying conditions and resulting prices be expected to persist into the future? Or, might such a view of the future be considered too rosy? Despite the current trends, what other futures might present themselves instead? What future changes to underlying key drivers might occur? Which of these key drivers is most difficult to predict? If a number of futures could be possible, then what range of outcomes might California face, and with what effect on prices, on end users' gas bills, and on the state's progress toward reducing GHG emissions? Do these ranges of possible outcomes represent vulnerabilities to California, or opportunities? Staff explored these questions by modeling the worldwide natural gas market.

Modeling Analysis

The Business-as-Usual Starting Point: A Reference Case

The basic approach is to start with a "reference case" set of assumptions, then create several "changed cases" by selecting a plausible range of future values for a few "key" independent variables—those input assumptions expected to significantly affect the results and that, in return, have a significant amount of uncertainty about their actual future states. Consequently, many of the assumptions are the same in all cases. It is relatively straightforward to describe and compare how the input assumptions vary across the cases.

Staff took an econometric modeling approach, with a few exceptions, to building the assumptions for the Energy Commission's Reference Case. The approach assumed that past observances are useful predictors of future outcomes. Regression analyses were performed to discover highly predictive explanatory variables and to create equations that link the explanatory variables to historically observed outcomes. The equations were then used as a forecasting tool, a use that presumes that the relationship (between independent and dependent variables) that was observed to hold in the past will continue to hold in the future. Sometimes this approach is referred to a "business-as-usual" approach. The Reference Case generally represents what the commercial agents in the worldwide gas market would do if unconstrained by new policies or prohibitions and not given new incentives. It is not meant to be a most likely or best guess view of what the actual future will be.

Highlights of Draft Report's Modeling Results

The Reference Case results suggest that the combination of recession-driven weak demand and abundant domestic supply has driven current wholesale market prices significantly below the hurricane-driven highs of a few years ago. These conditions are projected to be temporary as:

- Future demand increases with economic recovery and diminishing opportunities on the production side (drill-it-or-lose-it leasing, profit-rich natural gas liquids, sweet spot plays that are very productive).
- Prices rise as production marches up the marginal cost supply curve, which has shifted considerably due to the technological innovations described above.
- Even with returning demand, prices could plateau at about $6.00/MMBtu ($2010).

The future also could be much different than the business-as-usual Reference Case suggests.

On the supply side, controversies surround potential public health, safety, and environmental impacts of natural gas production and transportation activities and could result in significantly higher gas production and transportation costs either to avoid or to reduce the impacts. Local drilling embargoes could entirely deny access to significant portions of this growing domestic resource. On the other hand, further technological innovations and improved "best practices" could completely or partially offset these challenges. How these issues will play out cannot be known now, increasing the uncertainty inherent in any assessments of future gas market conditions.

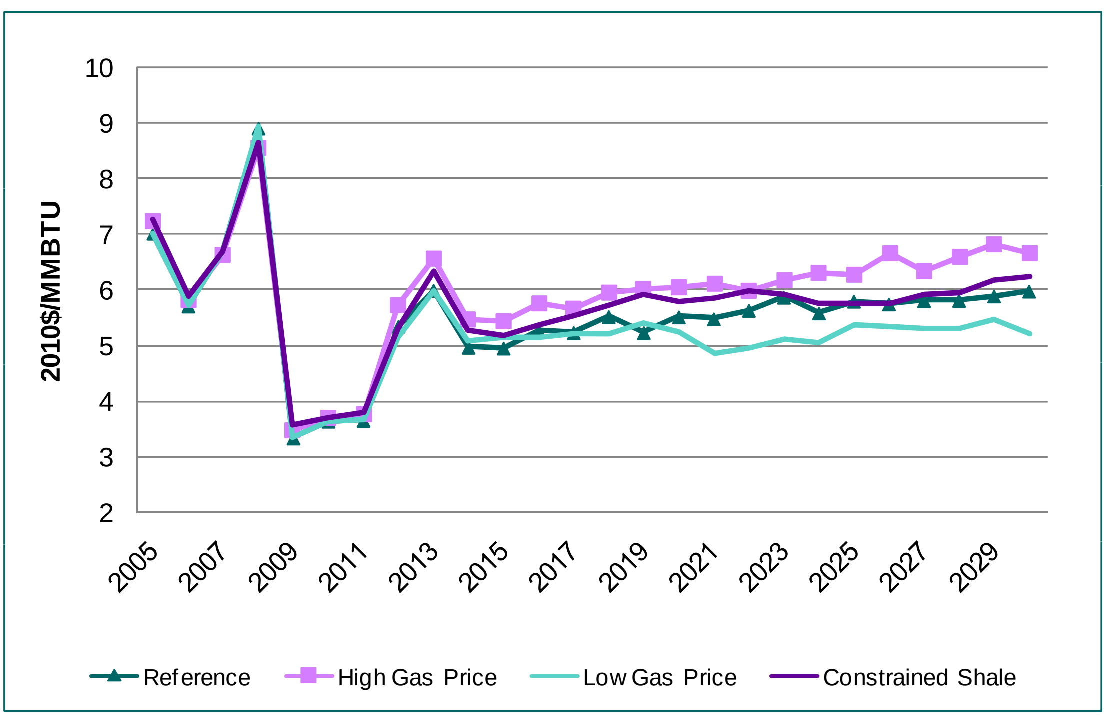
On the demand side, environmental and energy policies that affect electricity generation from any generation fuel type will affect the future amount of natural gas combusted by power plants, either because gas-fired generation is already fueling the marginal electricity supply or is among the most cost-competitive generation to build. For example, widespread replacement of coal-fired or nuclear power plants driven by air quality or safety concerns will increase natural gas fuel demand for electric generation, as would significantly increased electric vehicle recharging loads. On the other hand, increased penetration of energy efficiency and conservation programs; nongas electricity generation by renewable sources, such as geothermal, wind, solar, and biofuels; or increased efficiencies gained by combined heat and power generation would all act to reduce generation from fossil fuels. But just as with the supply-side drivers, how these issues will play out in the future cannot be known now. The fact of these considerable uncertainties and their potentially significant effect on future natural gas supply and demand (and consequently price) must be expressly taken into account in any assessment of future gas market conditions that is to be useful.

This assessment will provide useful information on potential market outcomes to support policy decisions that require assumptions be made about future gas market activities without accurate predictors. Computer modeling is an analytic tool to help achieve that objective. The assessment employs a study design with multiple scenarios and sensitivities. The reasons or issues on which each case is focused are explained and descriptions of the assumed future conditions underlying each case are presented. The goal is to better understand the potential vulnerabilities or opportunities that California could face under different future conditions.

Staff constructed three "changed" cases, specifically designed to move national natural gas market prices to levels higher or lower than seen in the Reference Case. Plausible values for the future states of key price drivers that would be expected to achieve that effect were selected. A key term here is "plausible." The conditions underlying each case could plausibly occur; there is no defensible basis for claiming how much more likely one case is than another. Staff includes such cases to guard against the risk of one-sided bias. Rather than presenting one conditional estimate that may be too rosy, a number of plausible outlooks are provided, with the differences among their underlying assumptions identified and discussed. This shifts the focus of discussion to gaining a better understanding of the underlying drivers of modeling outcomes, the uncertainties involved in predicting their future states accurately, and the reasons given for having selected the specific input values from the range of other plausible values that might have been selected instead.

Figure ES-3 shows the model's equilibrium condition results for the annual average spot market gas prices at the Henry trading hub for the Reference Case and the three cases designed to move national gas prices: the High Gas Price, the Low Gas Price, and the Constrained Shale Gas cases.

Figure ES-3: Henry Hub Daily Spot Market Natural Gas Prices Across Cases Designed to Move Gas Prices



Source: California Energy Commission staff analysis.

As designed, the resulting prices from the High Price and Low Price cases bound range of Henry Hub spot market gas prices across staff's cases:

- The High Gas Price Case has prices 9.8 percent higher than the Reference Case's 2014 to 2022 average price and 11.6 percent higher than its 2023 to 2030 average.
- The Low Gas Price Case has prices 3.5 percent lower than the Reference Case's 2014 to 2022 average price and 9.4 percent lower than its 2023 to 2030 average.

Staff constructed two additional changed cases, specifically designed to move California natural gas demand to levels both higher and lower than seen in the Reference Case. Plausible values for the future states of key demand drivers that would be expected to achieve that effect were selected. In these cases, the focus is on demand-related impacts, such as the potential future total cost of natural gas and GHG emissions from gas combustion. Particular attention was paid to power generation natural gas demand in California. Electric generation gas demand is the end-use sector that is growing rather than declining or remaining level. Due to the variety of energy and environmental policies aimed at influencing both the total amount of electricity consumed and the mix of generating resources (that is, what fraction is supplied by fossil, hydroelectric, nuclear, or renewable generators), there is much uncertainty about future gas demand for electric generation, both in California and nationally.

A snapshot description of the assumption differences across the cases, as well as selected United States and California model results for 2022, are provided in **Table ES-1** and **Table ES-2**. Focusing on California's natural gas use for power generation, staff "post-processed" (four selected output metrics), from 2017, 2022, and 2030 model results, which are displayed in **Table ES-1** and **Table ES-2**. These include annual generation gas demand, fuel cost, combustion-related carbon dioxide (CO_2) emissions, and potential emission allowance costs.

Table ES-1: Summary of World Gas Trade Model Key Driver Assumptions and Results, 2022

	Reference Case	High Gas Price Case	Low Gas Price Case	Constrained Shale Case	High CA Gas Demand Case	Low CA Gas Demand Case	Lowered Pressure Case
Results in 2022							
DEMAND							
US Tcf/yr	25.30	25.05	25.92	24.15	25.10	25.16	25.21
US Gas-Fired Electricity Generation Tcf/yr	8.47	9.36	8.75	8.12	8.46	8.41	8.44
CA Tcf/yr	2.19	2.12	2.24	2.10	2.25	2.14	2.18
CA Gas-Fired Electricity Generation Tcf/yr	0.65	0.66	0.66	0.63	0.72	0.61	0.65
SUPPLY							
US Natural Gas Dry Production Tcf/yr	24.78	22.35	25.56	23.47	24.91	24.92	24.75
US Shale Tcf/yr	12.23	8.76	13.59	10.89	12.25	12.34	11.95
US LNG Tcf/yr	1.07	1.84	0.92	1.25	1.07	0.99	1.04
Canadian Imports Tcf/yr	3.48	4.53	3.64	3.04	3.32	3.30	3.28
Exports Tcf/yr	2.5	3.82	2.63	2.1	2.72	2.67	2.35
PIPELINE CAPACITY							
Cumulative New Capacity to CA (Tcf) (aggregated from 2010 to 2022)	0.08	0.12	0.06	0.09	0.41	0.07	0.09
Pipeline Utilization; % of total (EPNG+TW+MJ/ GTN/ KRGT/ Ruby)*	36.82/68.46/ 72.87/47.72	34.52/62.07/ 67.84/48.4	35.11/81.55/ 70.7/39.04	36.09/59.58/ 66.77/45.89	43.74/70.87/ 74.90/35.39	40.22/71.29/ 69.88/43.84	36.3/89.5/ 65.1/31.1
PRICES							
Price at Henry Hub ($2010)/MMBtu	5.63	5.98	4.94	5.96	$5.66	5.49	5.59
Basis to CA Border at Topock ($2010)/MMBtu	0.26	0.19	0.31	0.28	0.29	0.23	0.27
Basis to Malin ($2010)/MMBtu	-0.08	-0.13	-0.03	-0.05	-0.05	-0.11	-0.06

*El Paso Natural Gas (EPNG) Transwestern (TW) Mojave (MJ) TransCanada Gas Transmission Northwest (GTN) Kern River Gas Transmission (KRGT) Ruby Pipeline (Ruby) CA (California)

Table ES-1: Summary of World Gas Trade Model Key Driver Assumptions and Results, 2022 (Continued)

	Reference Case	High Gas Price Case	Low Gas Price Case	Constrained Shale Case	High CA Gas Demand Case	Low CA Gas Demand Case	Lowered Pressure Case
Key Assumptions							
Average Annual GDP Growth Rate	2.6%	3.5%	2.1%	2.6%	2.6%	2.6%	2.6%
Gas Technology Improvement Average Annual Growth Rate	1%	1%	1%	1%	1%	1%	1%
Total US Electricity Production (GWh)	4,766,558	4,819,407	4,735,485	4,766,558	4,778,471	4,760,187	4,766,558
US Electricity Resource Mix (% of total from Fossil/Nuclear/Hydro/Renew)	66.8/17.8/ 5.45/15.37	68.8/17.8/5.4/ 13.4	65.6/17.8/ 5.5/16.6	66.8/17.8/ 5.45/15.37	67.4/17.6/5.4/15.0	66.6/17.8/5.5/10.1	66.8/17.8/ 5.45/15.37
Total CA Electricity Production (GWh)	238,058	240,698	236,506	238,058	249,972	231,687	238,058
CA Electricity Resource Mix (% of total from Fossil/Nuclear/Hydro/Renew)	44.5/14.5/ 11.5/29.4	45.0/14.5/ 11.4/29.1	44.3/14.5/ 11.6/29.6	44.5/14.5/ 11.5/29.4	55.8/10.9/11.0/22.4	38.6/14.5/11.8/34.1	44.5/14.5/ 11.5/29.4
When CA Meets Maximum RPS Target	On Time	On Time	On Time	On Time	2030	On Time[4]	On Time
When Other States Meet Individual Maximum RPS Targets	5 yrs late	10 yrs late	On Time	5 yrs late	5 yrs late	5 yrs late	On Time
Additional US Coal Generation Converts to Natural Gas	0	50 GW	0	0	0	0	0
Constrain/Augment Natural Gas Resources							
US	NY	PA, NY, CO and WY	Upper End of Range	NY	NY	NY	NY
World	IIV enters marker in 2020[2]	IIRV Constrained[1]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]
LNG Exports	Allowed but not imposed	Imposed LNG Exports	Allowed but not imposed	Allowed but not imposed	Allowed but not imposed	Allowed but not imposed	Allowed but not imposed
Pipeline Capacity Additions (Model feature turned On/Off)	ON	ON	ON	ON	ON	ON	OFF[3]
PG&E Backbone Capacity Reduction Constraint, MMcf/d	None	None	None	None	None	None	300 on Baja/200 on Redwood
Additional Environmental Mitigation Cost ($2005/Mcf)	N/A	$0.40/Mcf shale $0.20/Mcf Conv	N/A	$0.40/Mcf shale $0.20/Mcf Conv	N/A	N/A	N/A

Source: California Energy Commission staff draft analysis
1 Note: IIRV refers to Iran, Iraq, Russia, and Venezuela.
2 Note: IIV refers to Iran, Iraq, and Venezuela.
3 Note: Capacity additions off for years 2012 – 2016.
4 Note: Continues to grow to 40 percent by 2027 and then stabilizes.

Table ES-2: Estimates of California Power Generation Sector Gas Demand, Gas Costs, Combustion CO_2 Emissions, and Minimum CO_2 Allowance Costs by Case

Selected California Power Generation Sector Results	Reference	High Gas Price	Low Gas Price	Constrained Shale	High CA Gas Demand	Low CA Gas Demand
2017						
Gas Demand (Bcf/Yr)	696.6	683.3	694.3	681.3	730.7	683.5
Combustion CO_2e Emissions (Millions Tonnes CO_2/yr)	38.5	37.8	38.4	37.7	40.4	37.8
Gas Costs (Millions $2010/yr)	$4,285.5	$4,498.0	$4,292.4	$4,401.4	$4,562.7	$4,197.7
CO_2e Allowance Costs (Millions $2010/yr)	$465.2	$456.3	$463.6	$455.0	$488.0	$456.4
2022						
Gas Demand (Bcf/yr)	650.7	660.2	660.2	626.8	720.9	609.3
Combustion CO_2e Emissions (Millions Tonnes CO_2/yr)	36.0	36.5	36.5	34.7	39.9	33.7
Gas Costs (Millions $2010/yr)	$4,310.1	$4,576.6	$3,932.4	$4,390.0	$4,679.2	$4,080.0
CO_2e Allowance Costs (Millions $2010/yr)	$555.1	$563.2	$563.2	$534.7	$615.0	$519.8
2030						
Gas Demand (Bcf/yr)	658.6	686.7	690.8	639.1	862.9	543.1
Combustion CO_2e Emissions (Millions Tonnes CO_2/yr)	36.4	38.0	38.2	35.4	47.7	30.0
Gas Costs (Millions $2010/yr)	$4,619.7	$5,303.7	$4,199.8	$4,726.1	$5,848.9	$3,753.8
CO_2e Allowance Costs (Millions $2010/yr)	$829.3	$864.8	$869.8	$804.8	$1,086.6	$683.9

Source: California Energy Commission staff analysis. These are estimates.

Highlights of Post-Workshop Sensitivity Analyses

Chapter 5 contains a complete description of staff's post-workshop sensitivity studies, compares their results to the results of staff's draft report cases, and offers conclusions on how to interpret and use the findings. That discussion is summarized below.

Many parties at the September 27, 2011, workshop on the staff draft *Outlook* commented that the range of Henry Hub prices across the cases seemed narrower than they would have expected. Henry Hub, located in Erath, Louisiana, is considered the reference point for natural gas prices in the United States. Discussion at the workshop and subsequent written comments identified a few key drivers of price results as assumptions on which to focus additional scrutiny. The most significant include staff's estimates of:

- The amount of natural gas that is technically recoverable, which generally grows over time in response to technology innovation.
- The amount of natural gas that is economically recoverable, which grows with either decreasing costs of producing gas or rising prices paid for gas.

Staff chose to make significant changes to the assumptions about the *finding and development cost environment* of natural gas that underlies the marginal production cost curves. The marginal cost profile links the marginal capital cost of production to the quantity of gas reserves that economic agents can develop. These cost curves represent the capital expenditures needed to expand the natural gas resource base and vary from location to location. These costs depend on two important parameters:

- Current state of knowledge of the resources
- Current level of technology

In the Reference Case, staff used a finding and development cost assumption that was at the median of what was observed over the historical period of 1960 to present, known as the "Probability 50" (or "P50") assumption. This means, in the past, finding and development costs were equally likely to be higher or lower. Staff developed alternative assumptions about the future finding and development cost environment that are higher and lower than the Probability 50 value that was assumed in the Reference Case. For the high finding and development cost environment assumption, staff used a "Probability 10" (or "P10") assumption—a very high cost of finding and developing gas production in the future that has only been reached or exceeded during 10 percent of the historical cost record. This will generate high cost of gas and high natural gas price forecast. For the low finding and development cost environment assumption, staff chose to use a "Probability 90" (or "P90") assumption—a very low finding and developing cost level which has been reached or exceeded during 90 percent of the historical record. This will generate low cost of gas and low natural gas price forecast.

A short summary of assumptions and differences across the sensitivity cases, which are fully described in Chapter 5 are represented in **Table ES-3** and **Table ES-4.** Focusing on California's natural gas use for power generation, staff "post-processed" (four selected output metrics), from 2017, 2022, and 2030 model results for the sensitivity cases, which are displayed in **Table ES-3** and **Table ES-4**. These include annual generation gas demand, fuel cost, combustion-related carbon dioxide (CO_2) emissions, and potential emission allowance costs.

Table ES-3: Summary of World Gas Trade Model Key Driver Assumptions and Results for Sensitivity Cases, 2022

	Reference Case	Sensitivity Case I	Sensitivity Case II	Sensitivity Case III	Sensitivity Case IV	Sensitivity Case V	Sensitivity Case VI
Results in 2022							
DEMAND							
US Tcf/yr	25.30	22.18	28.2	28.99	22.47	22.01	22.57
US Gas-Fired Electricity Generation Tcf/yr	8.47	7.52	9.33	9.43	8.45	8.29	8.87
CA Tcf/yr	2.19	1.94	2.43	2.49	1.91	1.87	1.86
CA Gas-Fired Electricity Generation Tcf/yr	0.65	0.58	0.72	0.73	0.60	0.59	0.59
SUPPLY							
US Natural Gas Dry Production Tcf/yr	24.78	22.36	27.00	27.71	19.93	18.90	19.36
US Shale Tcf/yr	12.23	10.88	12.83	14.73	7.93	6.85	7.33
US LNG Tcf/yr	1.07	1.07	1.07	1.07	1.07	1.07	1.07
Canadian Imports Tcf/yr	3.48	2.22	4.61	4.48	3.16	3.22	3.16
Exports Tcf/yr	2.5	2.24	2.82	2.60	2.16	2.39	2.43
PIPELINE CAPACITY							
Cumulative New Capacity to CA (Tcf) (aggregated from 2010 to 2022)	0.08	0.14	0.09	28.09	0.02	0.15	0.12
Pipeline Utilization; % of total (EPNG+TW+MJ/ GTN/ KRGT/ Ruby)*	36.82/68.46/ 72.87/47.72	33.3/53.28 61.04/50.46	39.32/85.94 78.08/44.29	38.68/90.76 80.37/42.24	32.57/49.83 60.12/51.83	31.93/49.83 53.01/47.95	32.37/46.79 55.25/48.40
PRICES							
Price at Henry Hub ($2010)/MMBtu	5.63	6.62	4.67	4.47	7.13	7.21	7.13
Basis to CA Border at Topock ($2010)/MMBtu	0.26	0.31	0.19	0.21	0.35	0.37	0.35
Basis to Malin ($2010)/MMBtu	-0.08	0.05	-0.13	-0.11	0.08	0.09	0.10

*El Paso Natural Gas (EPNG) Transwestern (TW) Mojave (MJ) TransCanada Gas Transmission Northwest (GTN) Kern River Gas Transmission (KRGT) Ruby Pipeline (Ruby) CA (California)

Table ES-3: Summary of World Gas Trade Model Key Driver Assumptions and Results for Sensitivity Cases, 2022 (Continued)

	Reference Case	Sensitivity Case I	Sensitivity Case II	Sensitivity Case III	Sensitivity Case IV	Sensitivity Case V	Sensitivity Case VI
Key Assumptions							
Average Annual GDP Growth Rate	2.6%	2.6%	2.6%	2.1%	3.5%	3.5%	3.5%
Gas Technology Improvement Average Annual Growth Rate	1%	1%	1%	1%	1%	1%	1%
Total US Electricity Production (GWh)	4,766,558	4,766,558	4,766,558	4,735,485	4,819,407	4,819,407	4,819,407
US Electricity Resource Mix (% of total from Fossil/Nuclear/Hydro/Renew)	66.8/17.8/ 5.45/15.37	66.8/17.8/ 5.45/15.37	66.8/17.8/ 5.45/15.37	65.6/17.8/ 5.5/16.6	68.8/17.8/5.4/ 13.4	68.8/17.8/5.4/ 13.4	68.8/17.8/5.4/ 13.4
Total CA Electricity Production (GWh)	238,058	238,058	238,058	236,506	240,698	240,698	240,698
CA Electricity Resource Mix (% of total from Fossil/Nuclear/Hydro/Renew)	44.5/14.5/ 11.5/29.4	44.5/14.5/ 11.5/29.4	44.5/14.5/ 11.5/29.4	44.3/14.5/ 11.6/29.6	45.0/14.5/ 11.4/29.1	45.0/14.5/ 11.4/29.1	45.0/14.5/ 11.4/29.1
When CA Meets Maximum RPS Target	On Time	On Time	On Time	On Time	On Time	On Time	On Time
When Other States Meet Individual Maximum RPS Targets	5 yrs late	5 yrs late	5 yrs late	On Time	10 yrs late	10 yrs late	10 yrs late
Additional US Coal Generation Converts to Natural Gas	0	0	0	0	50 GW	50 GW	90 GW
Constrain/Augment Natural Gas Resources							
US	NY	NY	NY	Upper End of Range	PA, NY, CO and WY	PA, NY, CO and WY	PA, NY, CO and WY
World	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]	IIRV Constrained[1]	IIRV Constrained[1]	IIRV Constrained[1]
LNG Exports	Allowed but not imposed	Allowed but not imposed	Allowed but not imposed	Allowed but not imposed	Imposed LNG Exports	Imposed LNG Exports	Imposed LNG Exports
Pipeline Capacity Additions (Model feature turned On/Off)	ON	ON	ON	ON	ON	ON	ON
PG&E Backbone Capacity Reduction Constraint, MMcf/d	None	None	None	None	None	None	None
Additional Environmental Mitigation Cost ($2005/Mcf)	N/A	N/A	N/A	N/A	$0.40/Mcf shale $0.20/Mcf Conv	$0.70/Mcf	$0.40/Mcf shale $0.20/Mcf Conv
Cost Environment	P50	P10	P90	P90	P10	P10	P10

Source: California Energy Commission staff draft analysis
1 Note: IIRV refers to Iran, Iraq, Russia, and Venezuela.
2 Note: IIV refers to Iran, Iraq, and Venezuela.
3 Note: Capacity additions off for years 2012 – 2016.
4 Note: Continues to grow to 40 percent by 2027 and then stabilizes.

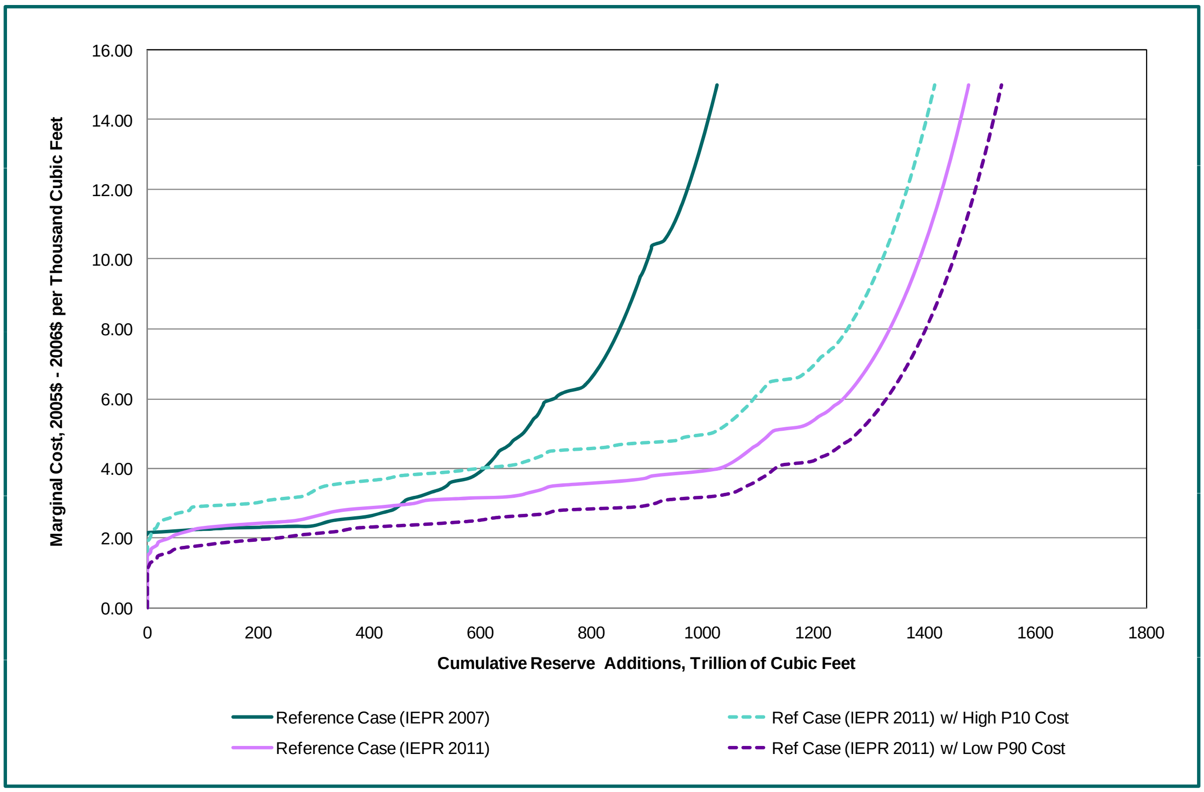
Table ES-4: Estimates of California Power Generation Sector Gas Demand, Gas Costs, Combustion CO_2 Emissions, and Minimum CO_2 Allowance Costs by Sensitivity Cases

Selected California Power Generation Sector Results	Reference	Sensitivity Case I	Sensitivity Case II	Sensitivity Case III	Sensitivity Case IV	Sensitivity Case V	Sensitivity Case VI
2017							
Gas Demand (Bcf/Yr)	696.6	648.3	747.7	747.2	640.7	631.2	627.6
Combustion CO_2e Emissions (Millions Tonnes CO_2/yr)	38.5	35.9	41.4	41.3	35.4	34.9	34.7
Gas Costs (Millions $2010/yr)	$4,285.5	$3,988.4	$4,922.0	$4,619.7	$4,138.7	$3,941.6	$3,854.6
CO_2e Allowance Costs (Millions $2010/yr)	$465.2	$432.9	$499.3	$488.0	$427.8	$421.5	$419.1
2022							
Gas Demand (Bcf/yr)	650.7	583.8	711.8	726.3	600.3	589.5	585.9
Combustion CO_2e Emissions (Millions Tonnes CO_2/yr)	36.0	32.3	39.4	40.2	33.2	32.6	32.4
Gas Costs (Millions $2010/yr)	$4,310.1	$3,867.2	$4,934.5	$4,326.3	$4,204.8	$3,826.3	$3,923.4
CO_2e Allowance Costs (Millions $2010/yr)	$555.1	$498.1	$607.3	$619.6	$512.2	$502.9	$499.9
2030							
Gas Demand (Bcf/yr)	658.6	582.0	730.1	771.8	624.1	610.1	606.3
Combustion CO_2e Emissions (Millions Tonnes CO_2/yr)	36.4	32.2	40.4	42.7	34.5	33.8	33.5
Gas Costs (Millions $2010/yr)	$4,619.7	$4,082.1	$5,638.8	$4,692.2	$4,614.8	$4,135.6	$4,190.5
CO_2e Allowance Costs (Millions $2010/yr)	$829.3	$732.8	$919.4	$971.8	$785.9	$768.3	$763.5

Source: California Energy Commission staff analysis. These are estimates.

Figure ES-4 shows the effect on the Reference Case natural gas marginal supply curve of changing its embedded assumption regarding the finding and development cost environment. Recall that **Figure ES-1** shows that the resource outlook in 2007 was about 700 Tcf of economically recoverable gas at a real price of $6 (2005$), but that has now increased to about 1,250 Tcf—an almost 80 percent increase. **Figure ES-4** shows that this finding of an economically recoverable resource base, much larger than thought just four years ago, is robust over a wide range of assumptions about future finding and development capital costs. Even at the unlikely high Probability 10 level of finding and development costs, almost 1,100 Tcf is economically recoverable—an almost 60 percent increase since the 2007 resource assessment.

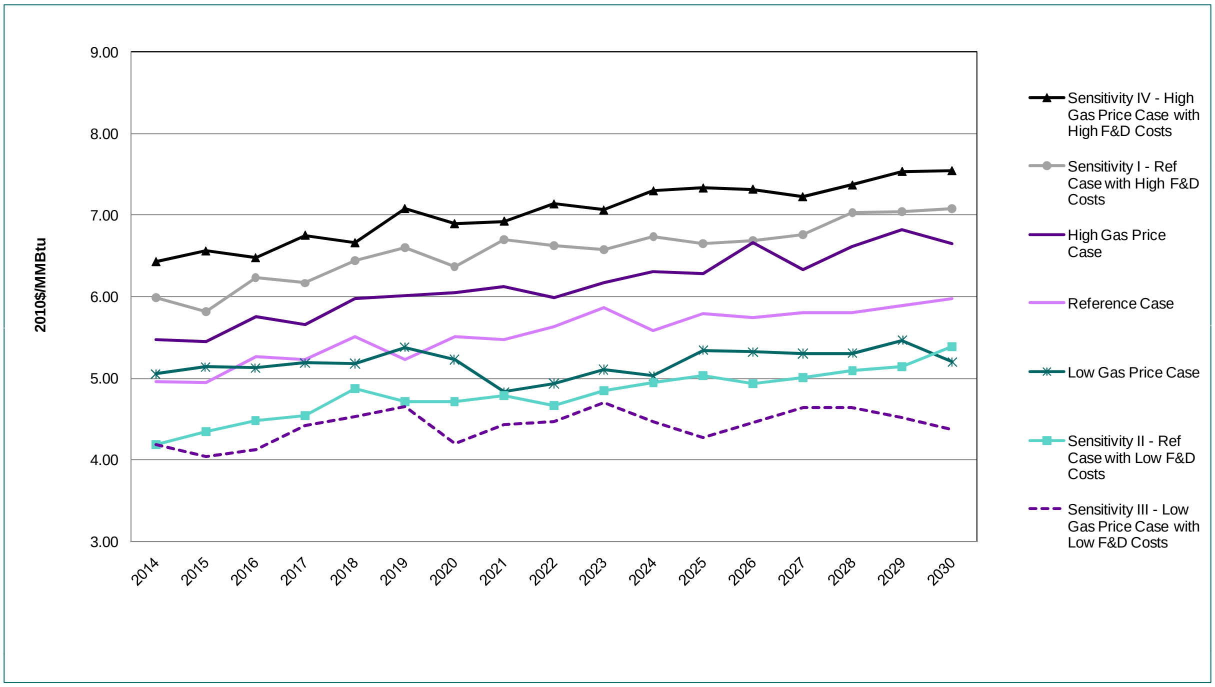
Figure ES-4: Effect on the Reference Case Natural Gas Marginal Supply Curve of Finding and Development Cost Environment



Source: California Energy Commission staff analysis; Baker Institute.

As they were designed to do, the sensitivity cases widened the range of natural gas price results that previously had been defined by the Low Gas Price and High Gas Price cases. **Figure ES-5** shows the effect of changing the assumption about the future finding and development environment on the annual average spot market prices of natural gas at Henry Hub from the original cases and the post-workshop sensitivity cases, in real terms ($2010/MMBtu).

Figure ES-5: Effect of Finding and Development Cost Environment on Original and Sensitivity Cases' Annual Average Spot Market Prices of Natural Gas at Henry Hub, $2010/MMBtu



Source: California Energy Commission staff analysis.

Sensitivity Cases I and IV address the question: How was the upper bound of prices changed by increasing the assumption about the future finding and development environment?

- The High Gas Price Case has prices 9.8 percent higher than the Reference Case's 2014 to 2022 average price and 11.6 percent higher than the 2023 to 2030 average.
- Sensitivity Case I, which adds a high (Probability 10) finding and development cost environment assumption to the Reference Case, increases the Reference Case average price over 2014 to 2022 by 19.1 percent and over 2023 to 2030 by 17.4 percent.
- Sensitivity Case IV, which adds the high (Probability 10) finding and development cost environment assumption to the High Gas Price Case, increases Reference Case average price over 2014 to 2022 by 27.5 percent and over 2023 to 2030 by 26.3 percent.

While the high (Probability 10) finding and development cost environment assumption in these two sensitivity cases does move prices significantly upward, these price outcomes are much less likely to actually occur for reasons detailed in Chapter 5. The Probability 10 finding and development cost conditions are less likely to occur than the Probability 50 conditions assumed in both the Reference Case and the High Gas Price Case, and even less likely to be sustained over the entire length of the simulation period.

Sensitivity Cases II and III address the question: How was the lower bound of prices changed by decreasing the finding and development cost environment assumption?

- The Low Gas Price Case has prices 3.5 percent lower than the Reference Case's 2014 to 2022 average price and 9.4 percent lower than the 2023 to 2030 average.
- Sensitivity Case II, which adds a low (Probability 90) finding and development cost environment assumption to the Reference Case, decreases Reference Case average price over 2014 to 2022 by 13.5 percent and over 2023 to 2030 by 13 percent.
- Sensitivity Case III, which adds the low (Probability 90) finding and development cost environment assumption to the Low Gas Price Case, decreases Reference Case average price over 2014 to 2022 by 18.2 percent and over 2023 to 2030 by 22.4 percent.

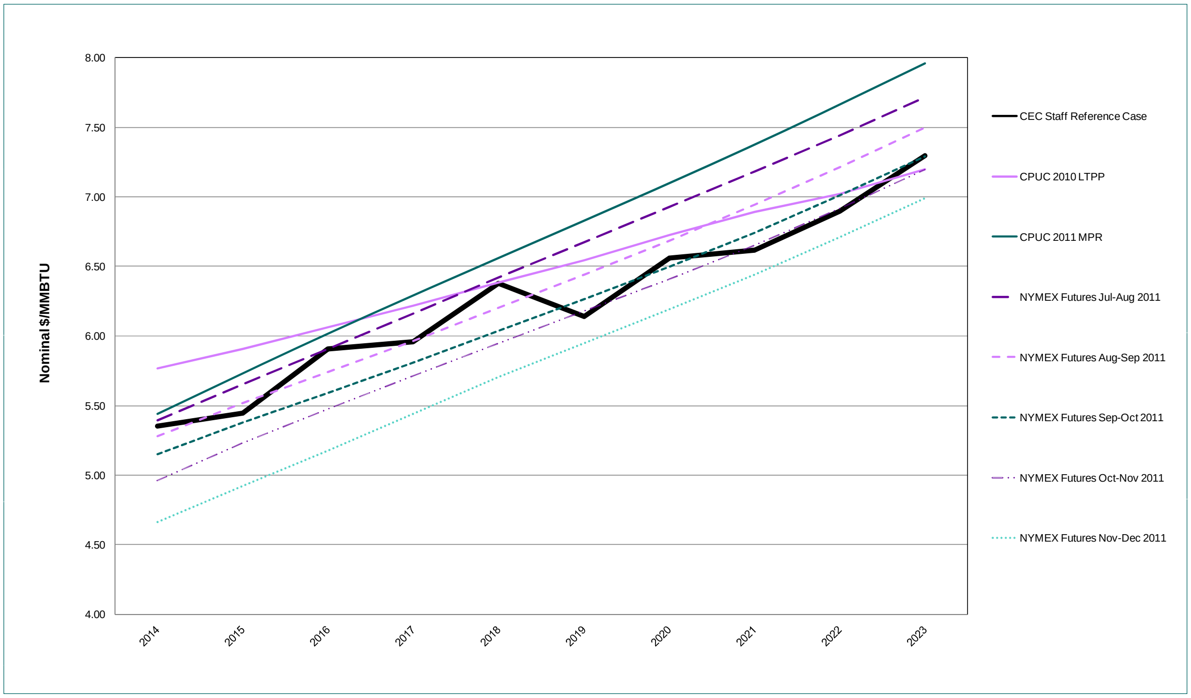
While the low (Probability 90) finding and development cost environment assumption in these sensitivity cases does move prices significantly downward, these price outcomes are much less likely to actually occur, for reasons detailed in Chapter 5. The Probability 90 finding and development cost conditions are less likely to occur than the Probability 50 conditions assumed in both the Reference Case and the High Gas Price Case, and even less likely to be sustained over the entire length of the simulation period.

Comparison of Futures Strips to Staff's Modeling Results

Chapter 3 has a brief discussion of futures-based natural gas price forecasts that have been used over the past decade in various California energy regulatory mechanisms. The most recent futures-based forecast discussed in that section is the one that the CPUC directed be used in the 2010 Long-Term Procurement Proceeding. Since then, the CPUC has directed that the 2011 Market Price Referent be calculated for the small renewable generator feed-in tariff program. These two gas price forecasts are shown in **Figure ES-6,** together with the Energy Commission's Reference Case. To get a sense of even more recent movements in spot prices, staff also added five dotted lines that successively apply the same CPUC-directed method for using futures strips as gas price forecasts, but to more current vintages of posted daily futures prices. These five gas futures price strips average daily closing Henry Hub prices over 22 consecutive trading days beginning about the 9th day of the 1st month through about the 11th of the following month.

Since the June-July vintage of the futures strips used to calculate the 2011 Market Price Referent's gas price forecast, the futures market has moved steadily lower month by month, passing lower than staff's Reference Case prices during this period. This movement is consistent with staff's assessment of the most recent market conditions, including recent trends in reductions in finding and development costs not reflected in the Probability 50 assumptions.

Figure ES-6: Staff Reference Case Price Results Compared to Recent Futures-Based Annual Average Henry Hub Natural Gas Spot Price, Nominal $/MMBtu



Source: Reference Case (Energy Commission staff analysis); CPUC 2010 LTPP (E3: Energy + Environmental Economics, April 2011 Evaluation Metric Calculator at http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/LTPP2010/LTPP_System_Plans.htm); CPUC 2011 MPR - (http://www.cpuc.ca.gov/NR/rdonlyres/CD8EC93F-F34E-484A-8804-594D79A654B2/0/DRAFT2011MPRModel.xls); NYMEX Futures - (http://intelligencepress.com/).

Given the modeling artifacts that affect staff's pre-2014 price results, some other source of estimates of near-term gas prices could fill this information gap. New York Mercantile Exchange future strips are a readily available source, and already accepted in various California energy regulatory mechanisms. Since the volume of trades on which New York Mercantile Exchange prices are based is higher in the first few years of the strips, these years can be a useful source of near-term price estimates. A disadvantage is that the estimates do not come with an explicit list of future conditions on which the market participants are essentially betting.

General Caveats on Price Results

The World Gas Trade Model price results represent the annual average of what prices would have to be for the investment decisions made by the model to be economic over the long term, under the various conditions assumed for each independent input variable. In this assessment, staff has varied assumptions about the future values of independent variables, focusing attention on those generally accepted to be key drivers of gas prices and demand over the long term.

Since staff did not vary input assumptions that can drive prices and demand in the short term, the World Gas Trade Model results do not reflect the effects of such regular seasonal or occasional expected or unexpected variations. Some examples include:

- Seasonal and year-to-year variations in cooling and heating degree days, which affect gas demand.
- Unusual severe weather events, such as hurricanes or widespread freezing temperatures, that may disrupt gas production, transportation, or demand.
- Annual variations in hydroelectric generation.

Staff's focus in this assessment has been on wholesale market activities. Although Chapter 4 discusses retail gas prices, and staff has provided retail prices associated with the original World Gas Trade Model cases on the Energy Commission's website, this assessment has not as comprehensively explored the range of future transportation costs (which make up more than half of residential rates) as it has commodity costs. Chapter 4 does point out potentially significant sources of uncertainty about future transportation rate components: pipeline integrity inspection and replacement costs, Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006) cap and trade emission allowance costs, public purpose program charges, other potential environmental costs, and so forth. To the extent that staff's assessments support energy policy and program decisions, and those decisions require information about retail natural gas and electricity prices, expanded efforts to explore a plausible range of future retail prices should be given a high priority.

CHAPTER 1: Introduction

Background

State government has an essential role to ensure that a reliable supply of energy is provided consistent with protection of public health and safety, promotion of the general welfare, maintenance of a sound economy, conservation of resources, and preservation of environmental quality (Public Resources Code Section 25300[b]). To perform this role, state government needs a complete understanding of the operation of energy markets, including electricity, natural gas, petroleum, and alternative energy sources, to enable it to respond to possible shortages, price shocks, oversupplies, or other disruptions (PRC Section 25300[c]). The California Energy Commission's timely reporting, assessment, forecasting, and data collection are essential to serve the information and policy development needs of the Governor, the Legislature, public agencies, market participants, and the public (PRC Section 25300[c]).

Purpose of the Natural Gas Market Assessment

This report does not to attempt accurate predictions of future natural gas market outcomes, but provides multiple plausible conditional estimates that explore potential vulnerabilities or opportunities California may face. Making accurate single-point forecasts of future gas prices and other market activities is not feasible and may not be particularly useful. This is a necessary consequence of the gas market's high complexity, large menu of competing options for actions, and deep uncertainties about future conditions, which are beyond one's control.

Worldwide natural gas markets, already linked to petroleum markets, have converged with electricity markets, a fact that multiplies the complexity of interactions among them. Concerns about greenhouse gas (GHG) emissions lead to an even greater role for natural gas in serving transportation demand, either directly or via electrification. The menu of options available to society for dealing with energy and climate change issues is large and varied, including such seemingly disparate actions as building zero net energy homes to building new nuclear powered generating plants. It is deeply uncertain now what will be the actual future state of various conditions that can significantly affect future natural gas markets (such as future emission reduction policies, future demand for gas-fired electric generation, and so forth). Even experts simply cannot agree on their likelihood.

These conditions of high complexity, many options for action, and deep uncertainty argue that market analysts move away from so-called "best guess" or "most likely" forecasts. Then what usefully can be done? Staff thinks it more useful to produce multiple plausible "conditional estimates" of the future to help explore what future natural gas market conditions might be. This approach gives the potential users of such estimates more information about the conditional nature of the estimates to help the users understand the potential consequences of their own use of a given estimate should the future turn out to be different.

Change in Modeling Approach From *2007 Integrated Energy Policy Report* (*IEPR*)

The most significant departure from past practices is the decision not to use estimates of natural gas demand from other Energy Commission staff work in this assessment. Typically, staff's *exogenous*, or external, input assumptions about demand for natural gas by Californians in the industrial, commercial, residential, and agricultural sectors have come from the Demand Analysis Office demand forecasts. Likewise, the exogenous assumptions about gas demand for electric generation across the Western Interconnection typically have come from Electricity Analysis Office production cost modeling results. Internal timing and modeling capability issues required staff in the Natural Gas Unit to team up with consultants with well-recognized expertise in natural gas markets to conduct this assessment. This assessment was conducted by a joint staff-consultant team, the members of which appear on the credits and acknowledgement pages as authors and consultants. Unless specified otherwise, use of the word "staff" in this report is meant to refer to this team.

Staff assisted Dr. Kenneth Medlock III, Rice University, with the specification of the worldwide gas market model's physical representation of the gas markets with which California most directly interacts (for example, adding a California-focused *topology*, which includes the geographical representation of gas supply and demand areas, or *nodes*, linked by pipelines). In addition, staff assisted Dr. Medlock with specification of the model's representation of certain California energy policy initiatives so California-specific, policy-relevant cases could be created.

Another significant departure from past practice is an increased reliance on econometric modeling to create many of the input assumptions to the natural gas market model. Therefore, this assessment makes use of a mixture of analytic techniques, which are all properly considered "modeling," but which employ a variety of differing models and modeling techniques. For example, this assessment relies on an econometric analysis of the state-level historical data for the electric generation sector compiled by the U.S. Energy Information Administration (EIA) performed by Dr. Medlock. Chapter 2 discusses general issues that arise in the use of models for forecasting and the influence they have on the study design employed in this assessment.

In this cycle, all natural gas market activity is being modeled annually. There is no seasonal, monthly, or daily information either as input or output. Necessarily, the modeling portion of this assessment excludes the operation of natural gas storage infrastructure, which is essentially a seasonal or shorter-term operation. This choice, made necessary by turnover in experienced staff, limits the use of the model to questions usefully addressed by annual modeling. Some annual gas volumes may be expressed as a daily average flow, in cubic feet per day; however, this result is calculated simply by dividing the annual volume in cubic feet per year by 365 days/year. Annual model results may be "post-processed" by applying typical seasonal factors based on past observances to approximate seasonal distributions of the annual model results, but this simple method is not meant as a substitute for seasonal or monthly modeling.

Scope and Organization of Report

Staff published the draft staff report *2011 Natural Gas Assessment: Outlook* in September 2011. A joint *2011 Integrated Energy Policy Report* (*2011 IEPR*) and Electricity and Natural Gas Committee workshop was held on September 27, 2011, to discuss and take comments on the draft report. Written comments were requested and received by parties by October 10, 2011. In response to workshop and written comments, staff conducted six new sensitivity studies using the World Gas Trade Market (WGTM). The results of this new work are discussed in Chapter 5. In addition, new supporting appendices have been added. Chapters 2, 3, and 4 remain essentially as they were in the staff draft report. Where typographical or errors were found, they have been corrected. At the September 27, 2011, workshop staff acknowledged that the High California (High CA) Gas Demand and Low California (Low CA) Gas Demand Cases had not been executed as planned or described in the report. Those cases have been rerun and the corrected results included in revised tables, figures and text of Chapters 3 and 4.

This natural gas market assessment begins by examining recent trends in demand, supply, infrastructure, and price. The results of this trends analysis will be published as a separate staff report, soon to follow this natural gas market assessment. It will update the trends analyses staff conducted for the *2009 IEPR*, which can be found at the Energy Commission's website for that proceeding.[1] An analysis of current trends identifies the underlying key drivers of the observed trends. The drivers may include economic, demographic, environmental, regulatory, and policy conditions. The current trends assessment report will also point out identified concerns or controversies that could affect the future states of key drivers, and the ability to predict them accurately. This examination of trends helps to understand what might be plausible ranges of uncertainty for the future states of these key drivers and guides the assumption changes in the case studies.

Chapter 2 describes the computer model of the natural gas market built and used in this assessment, how the study design is a product of both the limitations of modeling and the nature of the policy-relevant issues of interest, how issues-related questions direct the cases constructed, and the assumptions underlying each case. The model is a simplified mathematical representation of the complex interactions among world energy markets,

1 http://www.energy.ca.gov/2009_energypolicy/notices/2009-05-14_workshop_notice.html.

focusing on natural gas demand, supply, infrastructure, and price. The algorithms used in the modeling relate the input assumptions made about the future states of many exogenous independent input variables to the dependent output variables, the results of which should be interpreted as conditional estimates of future market activity. For model results to accurately predict the future, not only do the algorithms have to be accurate predictors of future relationships, but so do the assumptions made about the future states of the exogenous independent variables (at least the most significant ones).

This assessment will provide useful information on potential market outcomes to support policy decisions that require assumptions to be made about future gas market activities without accurate predictors. Better understanding the potential effects on market activities of the uncertainties in their key drivers is necessarily an objective of this assessment. Accordingly, the assessment employs a study design with multiple scenarios and sensitivities. The reasons or issues on which each case is focused are explained, and descriptions of the assumed future conditions underlying each case are presented. The goal is to better understand the potential vulnerabilities or opportunities that California could face under different future conditions.

Chapter 3 presents the natural gas market modeling results, including volumes of gas demanded, the type and location of gas supply sources being produced, the flows through pipelines, and the resulting prices. The model simulates wholesale market activity from wellhead production to the point where gas distribution utilities take control of the gas (at their *citygate*) for distribution to customers.

The model results are presented by comparing and drawing insights from the different cases for each of the following areas:

- Price: Prices at major market hubs, such as the one at Henry Hub, are compared over time and across the United States.
- Supply: The quantities of natural gas produced within the United States, the amounts imported, and the amounts from shale deposits are compared.
- Infrastructure: The amount of new pipeline capacity that the model estimates to be built in response to economic conditions is compared.
- Demand: The amount of natural gas consumed by various end-use sectors, including for electric generation is compared.

Chapter 4 describes conditional estimates of gas prices to end users and discusses uncertainties which affect future values these prices may take. Retail distribution of the gas is not included in the model results, nor is the final retail price. This is a “post-processing” activity in which the components of distributions costs are estimated and added to the commodity and transportation costs delivered at the citygate. Just as the wholesale market modeled cases have varied outputs for gas commodity and transportation costs, so too can the significant costs associated with the distribution function vary, depending on what assumptions one makes about the future conditions that affect distribution costs. Uncertainties about aging infrastructure replacement, public safety, environmental mitigation, and climate change policy implementation contribute to the range of variation future end-user gas prices may take. This chapter also provides an update on the current developments since the natural gas pipeline explosion in San Bruno, California, on September 9, 2010. The National Transportation and Safety Board issued a report in 2011 detailing its findings on the incident, and the California Public Utilities Commission (CPUC) has directed the State to perform hydraulic tests all pipelines lacking adequate records.

Chapter 5 describes six new sensitivity cases designed to address parties' comments on staff's initial draft analysis. A common comment was that the range of future gas prices across staff's cases seemed too narrow. Staff designed sensitivity cases to focus on key drivers of gas prices in the World Gas Trade Model (WGTM), further stressing or relaxing those assumptions to explore the effect on the resulting range of gas prices. The key drivers staff focused on include:

- The *finding and development* (F&D) cost environment portion of the marginal capital cost supply curve.
- The environmental mitigation cost component of operation and maintenance (O&M) costs of gas production.
- The increased demand for natural gas for electric generation if coal-fired generating capacity retires or converts to natural gas.

CHAPTER 2: Building the Natural Gas Market Model and Case Assumptions

This assessment employs a mixture of different mathematical modeling techniques and different computer models. Staff is committed to conducting the modeling portion of this market assessment as transparently as practicable. This report provides the broadest general explanations of the approach, assumptions, and calculations, as well as highlights in tables and graphs. Appendices provide more detail on modeling inputs, methods, and outputs. Subject to contractual protections of the consultants' intellectual property, staff will also post on the *2011 IEPR* website the detailed results of the gas market modeling for each case, extracted from the proprietary model output files to Microsoft Excel® worksheets.

This chapter focuses on some important general modeling concepts, including inherent limitations of models as accurate predictors of future conditions of complex systems. This limiting fact plays a significant role in the overall approach staff employed. The chapter describes in general the different models built and used in the assessment. It discusses how the specific design of the analysis accommodates the limitations of the models. The chapter also describes the specific issues each case is designed to address and lists the key input assumptions for each case. Since uncertainties in key drivers related to electricity system operations and policy impose significant uncertainties on future gas market activity, there is a section focusing on how electricity generation system-related assumptions change across the cases. Finally, this chapter describes some selected assumptions that remain constant and are important key drivers of results in all cases. The development of the alternative assumptions for the sensitivity studies is discussed in Chapter 5 and its supporting appendices.

General Comments About Building and Using Models

Before describing the specific models staff built and used in this assessment, it is useful to make some general statements about modeling and modeling terms. All models are mathematical simplifications of the real-world phenomena or activities they seek to represent. This basic fact is important to remember when using models to forecast future activities or conditions, especially models representing systems as complex as the natural gas and its related energy markets.

Understanding Important General Modeling Terms

Defining a few basic modeling terms now will help make more understandable the following explanation of how staff built the models, and why and how the specific cases were selected. In its simplest form, a model can be described as having equations that specify relationships between variables and operate on input assumptions to produce the output results. The inputs are referred to as *independent variables*—their values come from a source other than the equations that specify the relationships between variables in the model. The outputs are referred to as *dependent variables*—their values are dependent on both the value of the independent variables and the relationships in the equations that operate on them to produce the dependent variable results. Since the estimates made about the future state of the independent variables are made outside the model—their estimation process is considered exogenous to the model. The other variables are considered *endogenous* to the model, that is, they are specified by the model equations and are calculated by the model.

When using models to predict the future, getting an "accurate" result requires not only having specified accurate equations (meaning they describe well the future relationships between independent and dependent variables), but having made accurate guesses about what the future state of the independent variables will be. The predictive accuracy of model results may not be important if the model results are used for purposes that have no consequences if the model turns out to be inaccurate. However, elaborate and expensive computer modeling is typically employed to advise decisions that can have significant negative consequences if the future turns out differently than the independent variables and equations assumed in the model forecasts. A useful way to interpret the results of any model is as a conditional estimate. The accuracy of the results is conditioned on the accuracy of the model relationships and the assumptions made about independent variables.

Negotiating the Multiple Layers of Modeling

To add to the confusion, many modeling techniques and computer modeling software may be used all at once in a complex modeling effort such as this assessment. For example, analyses that employ a complex computer model—call it "Model M"—often use other models (and modeling techniques)—call them "model m"— to produce the estimates of the independent variables that serve as inputs to that Model M, the output of which can then be used as an estimate of the independent variables that serve as inputs to yet another model—call it "model p." In fact, this is the case with staff's natural gas modeling assessment. Using this simplified framework, Model M refers to the worldwide natural gas market model, called the WGTM, built for this assessment using the general computable equilibrium software platform MarketBuilder.[2] And, model m, in this case, is a collection of econometric models and simple spreadsheets staff used to build inputs for Model M.[3] The dependent

2 MarketBuilder is a software product of Deloitte LLP MarketPoint Services. For more information about how MarketBuilder works, see http://www.deloitte.com/view/en_US/us/Industries/power-utilities/deloitte-center-for-energy-solutions-power-utilities/marketpoint-home/marketpoint-marketbuilder/76c07c4886549210VgnVCM200000bb42f00aRCRD.htm.

3 An example of model m is the set of econometric analyses and models staff uses to create the initial "reference quantity" (or starting values) gas demands to input to the WGTM.

variable outputs of model m are staff's estimates of the independent variable inputs to Model M. In a process staff refers to as "post-processing," the dependent variable outputs of Model M are staff's estimates of the independent variable inputs to model p.[4] Many of the issue- or policy-relevant output metrics one hopes to get out of a complex assessment of natural gas market activities require post-processing. In the interest of transparency and so the reader can better understand staff's overall methodology and assumptions, this report attempts to make clear these Model M, model m, and model p distinctions in the following descriptions of this chain of modeling activities.

Applying General Commodity Market Modeling to Natural Gas

The MarketBuilder platform was used to construct staff's general equilibrium model representing the fundamentals of the worldwide natural gas market. MarketBuilder can be used to model commodity supply chains using networks of interrelated "agents" that seek to maximize their profit subject to the constraints assumed in the system. Using this computer platform, the market analyst constructs the geographic representation—the topology—of the commodity market, in this case the worldwide natural gas market, typically specifying more detail for the markets of most interest, usually the local ones. This includes locating the centers of demand for gas, including large gas consumers such as power plants, the interconnecting interstate and intrastate pipelines, liquefied natural gas terminals, and the various supply sources of gas.

Staff's analysis is based on the well-recognized global gas market expertise of consultant Dr. Kenneth Medlock III.[5] Dr. Medlock has used the MarketBuilder platform to construct a model of the worldwide natural gas markets, which he calls the Rice World Gas Trade Model (RWGTM). For this analysis, Medlock and staff worked closely together to modify his RWGTM for use in the *2011 IEPR* proceeding. The resulting modified model, called simply the WGTM, is the model used in staff's market assessment and described in this report. Staff relied on Dr. Medlock exclusively to specify the topology of gas markets in the United States and the rest of the world, while collaborating with him to specify a more detailed topology for the portion of the gas market with which California directly interacts.

In addition to specifying the geography of the market, the gas market analyst specifies the input assumptions that estimate quantities for the demand for gas, the price elasticities of demand for gas and its competing fuels, the price of competing fuels, the pipeline capacities and transportation costs, the size of the various gas supply resources, and the cost to extract

4 Examples of model p and post-processing include the set of spreadsheet models used to calculate end-user gas prices, total costs of natural gas by sector, and GHG emissions from the combustion of natural gas.

5 Dr. Medlock is the James A. Baker III and Susan G. Baker, Fellow in Energy and Resource Economics and Deputy Director of the Energy Forum of James A. Baker III Institute for Public Policy at Rice University in Houston, Texas.

them (for example, supply cost curves). These assumptions are all developed exogenously to the WGTM itself. They are the independent input variables that the WGTM acts on to produce its output, that is, the WGTM-calculated dependent variables referred to as "results."

Technically, the WGTM performs a dynamic spatial equilibrium linked through time by Hotelling-type optimization of resource extraction. This means that the WGTM takes the initial reference quantity of demand for gas, begins a least-cost selection (within specified constraints) of which supply options to produce and with which existing pipelines to transport the gas. It then calculates the annual average market price of gas based on the marginal cost of gas supply. Then it calculates the response of the initial demand level to this price to see if demand changes. It also may select, based on rational expectations of current and future conditions, including its endogenous prices, to build new pipelines linking supply to demand, if the market prices over the long term will support the assumed minimum rate of return on investment. The model iterates through this process until an equilibrium state is reached, where demand equals supply at an endogenously determined price. The resulting prices are best interpreted as conditional estimates of the future annual average prices that would have to be maintained in the market for all of the other results in the model (for example, demand levels, supplies produced, pipelines built and used) to be sustained over time.

The WGTM calculates as output regional prices, regional supplies and demands, and inter-regional flows, including transportation capacity expansions. Capacity expansions are determined by the endogenously calculated current and future prices along with exogenous assumptions about capital costs of expansion, operating and maintenance costs of new and existing capacity, and revenues resulting from future outputs and prices.

Awareness of Modeling Limitations Help Usefully Frame the Study Design

The preceding general comments about modeling all apply to staff's WGTM modeling. Since all of the underlying assumptions and estimation techniques employed to construct the independent variable inputs to the WGTM are exogenous to the WGTM itself, the resulting values of the dependent variables—the WGTM output—should be interpreted as conditional estimates of future market activity. For the WGTM results to be interpreted as "accurate predictors" of what future market activities actually will be, then the estimates of the future states of at least the most significant independent variables (sometimes called the key drivers of results) would also have to have been accurately predicted. Such accuracy is not feasible to achieve, given the number of complex interacting key drivers of WGTM results and the deep uncertainties affecting staff's ability to predict accurately their future states. What makes the modeling output conditional is not the kind of modeling employed, but the fact that the real-world activities the model seeks to represent are fundamentally characterized by high complexity, many alternative options for action, and deep uncertainty. These conditions are present in the related electricity and other energy markets as well.

Nevertheless, policy-making and decision-making still often require making some assumptions about future market conditions, even in the face of this great uncertainty. So, having a better understanding of the uncertainties and their effects can lead to more robust decisions—those having satisfactory consequences over a broad range of future conditions staff cannot predict or control. Building and running models to understand better the potential impact of the uncertainties on market outcomes thus can be very useful in helping to advise the decision-making. This necessarily implies that some combination of scenario or sensitivity analysis would be useful, and that is the approach staff took in this assessment.

Study Design Is Issues-Oriented

Having acknowledged the need to deal expressly with uncertainties of future market outcomes, the practical limits of time and staff resources require a narrowing of the questions or issues on which to focus the assessment. Staff made initial suggestions about scope and issues on which to focus at workshops in February and April 2011. Stakeholder comments have since provided useful feedback. The issues used to scope the modeling assessment are as follows:

- What potential vulnerabilities to high gas prices might California face in the future?
- What potential opportunities for low gas prices might California enjoy in the future?
- What potential vulnerabilities to higher gas demand in California might the State face in the future?
- What potential opportunities for lower gas demand in California might the State enjoy in the future?
- What potential vulnerabilities for gas system adequacy might California face as pipelines are temporarily removed from service or have their maximum operating pressures reduced while inspections to ensure pipeline safety are conducted, or remedial actions implemented?

Looking at both high and low cases helps guard against the potential consequences of one-sided biases. For example, decisions based on assumptions that future gas prices will be low could have significant negative consequences if gas prices turn out to be high, and vice versa. It depends on the direct consequences of the specific use of conditional estimates that turn out to be inaccurate predictors of the future. Generally, it is prudent for the users of any conditional estimate to examine the potential consequences of their use of one estimate for their specific purpose in the event the future turns out to be different from that estimate. This is especially true if the experts providing the estimate have no defensible argument for one estimate being more likely to occur than another. The users' own assessments of the potential regret associated with their use of available alternative estimates may help them choose which estimate is most prudent for them to use, if any. Having done so, their decisions have a better chance of being robust, that is, of performing acceptably over a wide range of possible futures. Gas market analysts can advise on these purpose-specific decision analyses but cannot conduct them, as they require knowledge about the specific uses of the estimates and the details about how consequences play out. For example, the question of what energy efficiency measure is cost-effective is as much about the conditional estimates of cost and performance of the proposed measures themselves as about the cost of the fuel their success may avoid.[6]

Choosing the Starting Point and Changed Cases

The basic approach is to start with a "reference case" set of assumptions, then create several "changed cases" by selecting a plausible range of future values for key independent variables — those input assumptions expected to affect significantly the results and that, in return, have a significant amount of uncertainty about their actual future states. Consequently, most of the assumptions are the same in all cases. Describing and comparing how the input assumptions vary across the cases are relatively straightforward. These descriptions are presented later in this chapter.

How did staff decide what cases to construct to specifically address the above issues, and where to start? The concept of a reference case was used, in the sense of being an initial, well-defined, and well-understood point of reference. This is neither meant to be a case with a consensus of agreement nor a case judged by anyone to be expected or most likely. (It may provide parties a common language with which to argue what futures are expected or most likely.)

Using Econometric Analyses to Build Reference Case Assumptions

Staff took an econometric modeling approach, with a few exceptions, to building the assumptions for the Reference Case. (This description has now moved into the previously discussed realm of model m.) The approach assumed that past observances are useful predictors of future outcomes. Regression analyses were performed to discover highly predictive explanatory variables and to create equations that link the explanatory variables to historically observed outcomes. The equations are then used as a forecasting tool, a use that presumes that the relationship (between independent and dependent variables) that was observed to hold in the past will continue to hold in the future. Sometimes this approach is referred to a "business-as-usual" approach. The reference case generally represents what the commercial agents in the worldwide gas market would do, if

6 For a discussion of how a regret analysis can help users of forecasts manage their risks of using forecasts that turn out to be inaccurate, see *Looking Before Leaping: Are Your Utility's Gas Price Forecasts Accurate?* Ken Costello, National Regulatory Research Institute, May 2010. http://www.nrri.org/pubs/gas/NRRI_gas_price_forecasting_may10-08.pdf.

unconstrained by new policies or prohibitions and not given new incentives. It is not meant to be a most likely or best guess view of what the actual future will be.

Computer models will produce accurate predictions of the future only if (1) the real-world relationships represented by the equations do not change over time, and (2) the future values of the independent variables on which the equations act are accurately predicted. Neither condition may be likely to occur. In fact, in the real world, agents can be expected to take actions to ensure that they do not. For example, novel future policy interventions or imposed constraints may alter the real-world relationships represented by the equations (for example, a structural change). Or guesses about the future state of an independent variable that is deeply uncertain may be poor (for example, garbage in, garbage out). These limitations do not make modeling-based analyses useless. The utility of the modeling depends on understanding its inherent limitations, designing the cases appropriately, and interpreting and using the results reflectively.

Building the Reference Case Assumptions

General Comments on the Reference Case Assumptions

This section generally describes the effort involved in developing a starting point for modeling the worldwide natural gas market and its associated energy markets. The effort requires specifying worldwide estimates for future states of the following inputs, among others:

- Quantity and location of gas demand by all sectors of the economy.
- Quantity, location, and development costs of all natural gas supply sources.
- Capacity, location, and cost of all transportation infrastructure, including LNG facilities.
- Initial fuel prices and price elasticities.
- Economic and demographic conditions.

There are too many input assumptions to fully describe in this report. More detail on the methods and assumptions employed to build these assumptions is provided in the presentation in Appendix B about the development of the Reference Case. Complete Reference Case WGTM outputs are also provided in Appendix C. A few selected Reference Case input assumptions, and how they are built, are described immediately below, while others are described further down with respect to how they have been modified by staff in the changed cases. Due to the importance of electric generation as a driver of gas demand, and the many uncertainties affecting the future mix of power generation sources, a section is included comparing how power generation sector assumptions change across cases.

To improve overall transparency of the modeling methods, as well as its results, this chapter ends with a discussion of some key assumptions that are common to all cases (not changing across cases) but that have significant influence on the results. For example, assumptions about price elasticity of gas demand by sector are important in understanding why the final output (equilibrium) gas demand from the WGTM, which responds to the price of gas in the model, may differ from the reference quantity gas demand assumption[7] initially input to the WGTM. Price elasticity determines the responsiveness of consumers on gas demand to the changes in the price. Also described are the method and values used to develop the allocation factors with which the WGTM calculates results at the level of the local gas distribution utility.

Describing Selected Reference Case Assumptions

Dr. Kenneth Medlock III conducted the regression analyses of historical observations of key drivers of activities in the worldwide gas market to develop the econometric equations and to identify the explanatory independent variables used to characterize input assumptions for the general computable equilibrium model (WGTM). The starting point case, which staff refers to as the Reference Case, mostly has assumptions developed by Medlock. This case represents a future in which commercial activity in the gas market (and related energy markets) proceeds as it generally has done so in the past, with some exceptions or constraints being imposed. As stated, this intended design means that the Reference Case represents more of a business-as-usual approach. It's not meant to be an accurate prediction of the future. Few think the future of U.S. and California energy markets will develop without significant structural changes being introduced. Even fewer can accurately predict what those will be.

Key input assumptions for the Reference Case, highlighting those that change in at least one of the changed cases, include the following:

- Average annual growth rate in gross domestic product (GDP) is 2.6 percent.
- The marginal cost curve for gas supplies reflects 2011 vintage state of knowledge about the underlying gas resource base and production technologies.
- Average annual rate of learning improvement in gas technology is 1 percent. [8]
- Shale gas development in New York is constrained per current moratorium.
- Iran, Iraq, and Venezuela do not enter the market until 2020.
- LNG exports are allowed to occur.[9]

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7 The "reference quantity gas demand assumption" is the estimate of gas demand that is input to the WGTM. The assumption itself is the output of the econometric modeling that is used to build assumptions about the future states of the WGTM's exogenous independent input variables. Every case has "reference" quantities of gas demand as inputs to its WGTM run. So, this is a completely different use of the same term "reference" than when it is used to refer to the Reference Case.

8 Learning improvement is increased productivity achieved through practice, self-perfection, and minor innovations. Staff considers this a conservative assumption.

- Pipeline capacity additions are allowed to occur.
- Individual states within the United States future power generation mix follow current trends based on U.S. EIA state level historical data except renewable generation:
  - California meets its existing Renewables Portfolio Standard (RPS) target on time in 2020.
  - Other states with RPS targets meet their targets five years late.
  - Growth of renewable generation in other states with no RPS targets follows past trends.

Other Reference Case assumptions are discussed below in the context of the changed cases that alter them.

Building the Assumptions for the Changed Cases

Overall Case Structure

Staff created three changed cases to focus on potential vulnerabilities or opportunities potential future gas prices may pose for California. Since California represents only a share of the worldwide gas market, moving the market price for gas tends to take changes to assumptions beyond California's borders. The High Natural Gas Price Case and Low Natural Gas Price Cases were created by changing a variety of international, national, and California-specific assumptions in ways anticipated to move natural gas prices higher and lower than in the Reference Case, respectively. Both demand- and supply-related assumptions were changed. The Constrained Shale Gas Case makes a few gas supply-related assumption changes from the Reference Case, which makes it more of a sensitivity case focused on the uncertainty of shale development going forward. Sometimes this report will refer to these cases collectively as those focused on price impacts or designed to move price. However, natural gas market prices are not the only model results of interest in these cases, as will be shown in Chapter 3's discussion of results.

Staff created two changed cases to focus on potential vulnerabilities or opportunities that the potential future demand for gas may pose for the State. Varying levels of demand for gas will have varying consequences to the total cost of gas to Californians and to the amount of GHG emissions from the combustion of the gas consumed. Although the WGTM does not calculate either total gas costs or emissions, staff makes some post-processed calculations to estimate them for each case of interest in Chapter 3. These cases are the High and Low CA

9 The phrase "allowed to occur" here means that their occurrence is not prohibited and that whether or not the feature appears in any case is dependent on the model's evaluation of the feature's commercial viability given the endogenous outlook for gas prices (past, present, and future) in that case.

Gas Demand cases and may be collectively referred to as cases "designed to move California gas demand."

Staff created one additional sensitivity case to examine the potential effect of temporarily reducing the maximum allowable operating pressure on certain PG&E pipelines. This is an attempt to see what effect ongoing inspection or possible mitigation activities related to pipeline safety might have on the annual modeling results in the Reference Case, and how such results may be informative, if at all.

Uncertainties about the potential future resolution of national-level and state-level environmental issues contribute significantly to the assumption building in all cases. Some issues affect the wide-ranging potential public safety and environmental effects of natural gas market activities. Some issues affect the public safety and environmental effects of electricity generation activities, which indirectly but significantly affect the natural gas market, as gas-fired generation experiences a growing role as a marginal supply of electricity. Issues relating to emissions contributing to climate change both directly and indirectly affect gas market activities. All of these, as well as uncertainties about the long-term growth of the economy, had an effect on the case construction.

The sections below first describe the changed cases designed to move national gas market prices higher or lower than in the Reference Case: the High Gas Price, the Low Gas Price, and the Constrained Shale Gas cases. Next are described the cases designed to move California's demand for natural gas: the High CA Gas Demand and Low CA Gas Demand cases. Finally, the Lowered Pressure Case is described, which is designed to examine the implications of what consumers could face if pipeline capacity reductions were to occur for a series of successive annual periods.

Additional sensitivities added after the September 27, 2011, Joint *IEPR* and Electricity and Natural Gas Committees Workshop are in Chapter 5.

High Gas Price Case Description

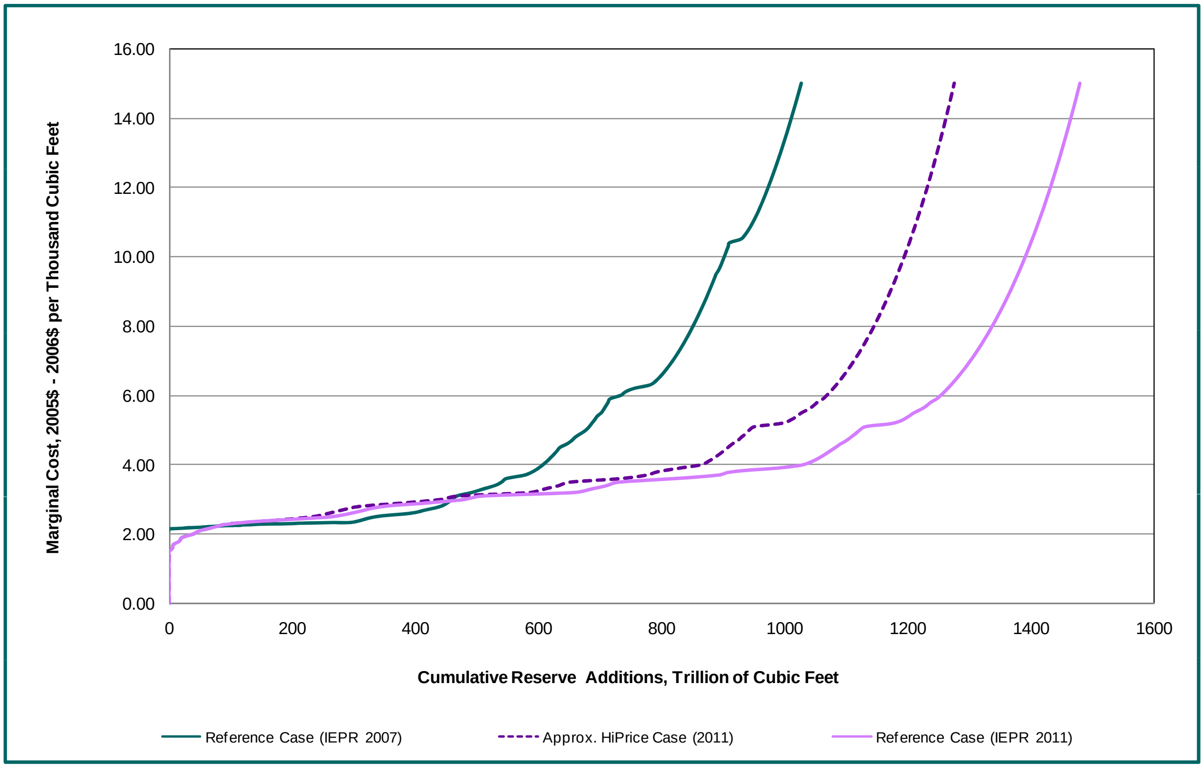
On the demand side, the economy is growing robustly—coal-fired power plant retirements and slowed renewable generation programs increase natural gas demand for electric generation. On the supply side, some jurisdictions further restrict the development of natural gas resources, particularly shale formations. Also, in places where production continues, environmental compliance costs rise as concerns about the safety of hydraulic fracturing continues. More specifically, the changes made to assumptions in this case include:

- Remove 50,000 megawatts (MW) of coal-fired generation—about 309,000 gigawatt-hours (GWh) of annual energy production.[10]
- Robust economic performance, with long-term annual economic growth averaging 3.5 percent.
- Delay RPS implementation so all states with RPS programs , excluding California, reach their maximum targets 10 years late (extra 5-year delay from the Reference Case's 5-year delay), as states grapple with budgetary concerns and other obstacles, including environmental.
- Robust LNG export capability developed and used—Kitimat (Canada, Apache), Sabine Pass (Cheniere), Lake Charles (BG), Freeport, and Cove Point.
- Environmental regulations add $0.40/Mcf to the operations and maintenance cost of developing shale formations and add $0.20/Mcf to conventional resources.
- Remove from development potential shales in particular regions, in particular those in Pennsylvania, New York, Colorado, and Wyoming. This will substantially alter the available gas resource, reestablish a merit order, and alter basis more than price.
- Introduce constraints on natural gas development in Iraq, Iran, Venezuela, and Russia.

Figure 1 shows how the individual assumption changes that affect gas supplies (available resource base) collectively act to shift the marginal supply curve significantly to the left. The Reference Case assumes the 2011 marginal cost curve, while the High Gas Price Case assumes the marginal supply cost curve marked Approximate High Price Case, which is much closer to the supply outlook in 2007, before shale gas reserve additions and production began to skyrocket.

10 This amount was distributed geographically using findings of an analysis by The Brattle Group of the future viability of existing coal-fired power plants under existing and potentially new air pollutant regulations. See *Potential Coal Plant Retirements Under Emerging Environmental Regulations*, Celebi, Graves, Bathla, and Bressan, The Brattle Group, December 8, 2010, www.brattle.com.

Figure 1: Effect on the Natural Gas Marginal Supply Curve of Assumption Changes for the High Gas Price Case



Source: California Energy Commission staff analysis.

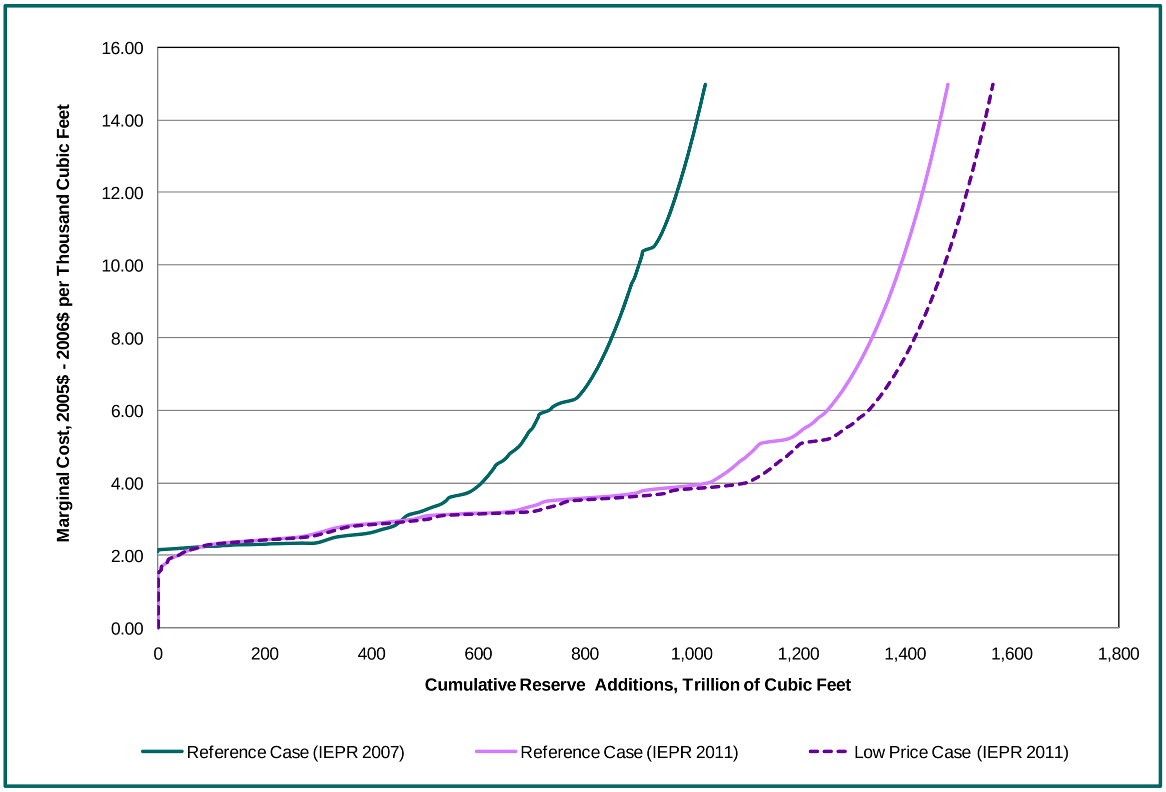
Low Gas Price Case Description

Technology development dominates this scenario. On the demand side, the economy is weak; all states with RPS programs comply on time. On the supply side, environmental concerns decrease as technological developments allow deployment of adequate environmental mitigation without significant overall cost increases; jurisdictions that in the past restricted natural gas development, and eased regulations. More specifically, the changes made to assumptions in this case include:

- Economic performance is weak, with long-term annual economic growth averaging 2.1 percent.
- No LNG exports are allowed, thus keeping North America isolated.
- Larger resource assessments (increase assessment size to upper range of published data) in the Marcellus, Haynesville, and Western Canadian shales.
- Iran, Iraq, and Venezuela enter the market unimpeded beyond prespecified dates.
- All states with RPS programs meet their maximum targets on time.

Figure 2 shows how assumption changes affect gas supplies (available resource base) collectively to shift the marginal supply curve to the right. The Reference Case assumes the 2011 marginal cost curve, while the Low Gas Price Case assumes the curve marked Low Price Marginal Cost Curve, which is a significant improvement in gas supply outlook.

Figure 2: Effect on the Natural Gas Marginal Supply Curve of Assumption Changes for the Low Gas Price Case



Source: California Energy Commission staff analysis.

Constrained Shale Gas Case Description

In this sensitivity case, environmental concerns, particularly about the treatment and disposal of water used in the hydraulic fracturing process, prompt many jurisdictions to implement additional regulatory requirements on further development of natural gas from shale formations. Regulatory compliance after 2013 adds another $0.40 per thousand cubic feet equivalent (Mcfe) to the cost of production of shale natural gas and $0.20/Mcfe on conventional production ($2005).

Staff's estimation of this additional mitigation cost divided costs into three categories: current level mitigation costs assumed in the Reference Case, additional groundwater protection mitigation, and additional state environmental mitigation taxes or levies.

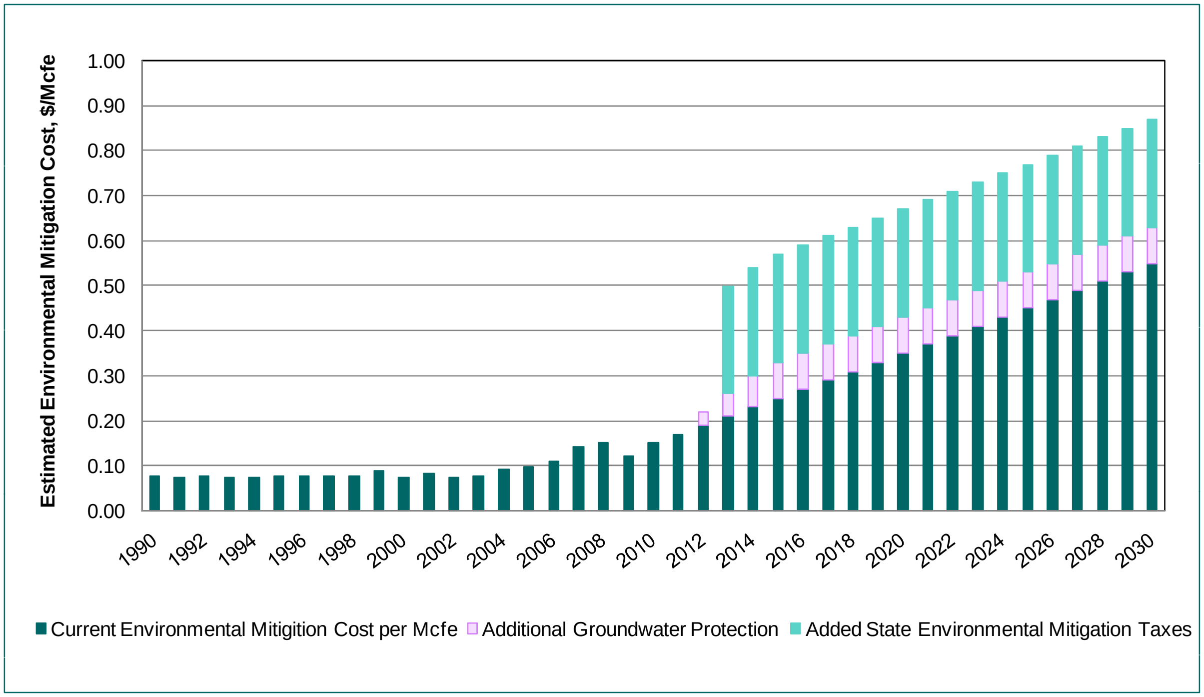
Current Environmental Mitigation Cost: Both the U.S. EIA and the American Petroleum Institute (API) supplied the raw data used in developing the forecasted number for this parameter. In the Reference Case, staff assumed that this category will grow at a nominal annual rate of $0.02/Mcfe per year. (The WGTM does not expressly assume the projected inflationary increase, since it uses a flat real O&M cost in $2005.)

Additional Groundwater Protection: Around 2002, mitigation costs started increasing, climbing a total of about $0.08/Mcfe in the succeeding five years. As a result, staff assumes that additional groundwater protection, including water treatment and disposal and better cement jobs for aquifer isolation, will result in a similar cost increase.

Added State Environmental Mitigation Taxes/Levies: The Commonwealth of Pennsylvania is considering a mitigation tax of about 4 percent to 8 percent of the wellhead price. If implemented in Pennsylvania, staff assumes other states will follow with similar levies. As a result, for this category, this analysis calculates an approximate mid-value of $0.24/Mcfe, starting in 2013.

Figure 3 charts the total estimated forecasted environmental mitigation cost. Between 2013 and 2030, nominal mitigation cost increases from about $0.50 per Mcfe to about $0.87 per Mcfe. Estimated real cost ($2005), thus, varies between $0.32 per Mcfe and $0.56 per Mcfe, resulting in additional environmental mitigation cost of $0.22 per Mcfe to $0.46 per Mcfe. Because staff intended to bracket the range of uncertainty in natural gas prices and supply, the Constrained Shale Gas Case assumes the aforementioned mitigation cost of $0.40 per Mcfe ($2005) for shale gas production and, because of the lesser water handling issues, $0.20 per Mcfe ($2005) for conventional gas production.

Figure 3: Estimated Environmental Mitigation Cost, Nominal $/Mcfe



Source: California Energy Commission staff analysis.

High CA Gas Demand Case Description

Assumption changes in this case are dominated by increased gas-fired generation to replace electricity from the state's two nuclear power plants, which are assumed not to be relicensed, to make up for slowing renewable generation development and to serve increasing electric vehicle charging and natural gas vehicle fueling. More specifically, the changes made to assumptions in this case include:

- Eliminate more than 34,000 GWh of California-located nuclear generation by 2025.
  - San Onofre Nuclear Generating Station Units 2 and 3 are not relicensed and stop generating after 2022.
  - Diablo Canyon Units 1 and 2 are not relicensed and stop generating after 2024 and 2025, respectively.
- Increase California RPS compliance only 1 percent per year until 2029, when 33 percent is reached.
- Double the amount of residential and commercial sector electric vehicle charging that is embedded in the Energy Commission's adopted *2009 IEPR* demand forecast, adding about 2,400 GWh by 2020 and 4,500 GWh by 2030.
- Add 200 million therms of natural gas transportation demand by 2020 and 400 million therms by 2030 (40 million – 60 million therms currently exist).

- Increase the annual average growth rate of overall California electricity demand by about 0.25 percent (to match the growth rate in High Demand Case of the adopted *2009 IEPR* demand forecast).

Low CA Gas Demand Case Description

Assumption changes in this case are dominated by accelerated renewable generation, both central station and distributed facilities, generally displacing gas-fired generation. Since distributed generation reduces electricity sales, on which RPS percent renewable obligations are measured, this case has some counterbalancing features. More specifically, the changes made to assumptions in this case include:

- Continue increasing California procurement of RPS-eligible renewable generation by 1 percent of retail sales per year between 2021 (when it is 34 percent) and 2027, leveling off at 40 percent in 2027 and beyond.
- Add additional non-RPS-eligible distributed renewable generation, about 6,000 MW by 2030, generating about 8,400 GWh (16 percent annual capacity factor).
- Slow annual average growth rate of overall California electricity demand by 0.15 percent (to match the Low Demand Case of the adopted *2009 IEPR* demand forecast).

Lowered Pipeline Pressure Case Description

This sensitivity case is intended to explore the implications of what consumers could face if pipeline capacity reductions of the assumed magnitudes were to occur for a series of successive annual periods. Since staff's WGTM analysis runs the model in annual mode only, discontinuities or impacts more likely to be seen with seasonal increases and decreases in demand cannot be detected. This case was designed to simulate some operational aspects of the pipeline system due to the changes ordered by the CPUC on PG&E since the San Bruno pipeline explosion. More details about this event are described in Chapter 5 of this report.

To date, certain pipelines on the PG&E system are operating at lower pressure pending validation of their maximum allowable operating capacity (MAOP). This might have changed by the time this report is posted in the Commission's website. Lowering the pressure on a pipeline has the effect of lowering the maximum operating capacity for the pipeline. The CPUC has ordered that all pipelines for which the gas transmission operators under its jurisdiction (PG&E, Southern Gas [SoCalGas], San Diego Gas & Electric [SDG&E] and Southwest Gas) do not have "traceable, verifiable, and complete" records of MAOP be pressure tested or replaced. These CPUC-jurisdictional gas utilities are launching efforts to review their systems and begin the required testing. Such testing, at times, requires taking lines out of service to perform the test. Should a line segment fail a test, it must be replaced, during which time affected customers would be out of service. In some situations, the gas utilities may choose to replace a segment rather than test it.

The Energy Commission understands that considerable effort is being made to prevent uncontrolled customer outages and minimize curtailments. In particular, the testing schedules attempt to ensure that no lines are out of service during the winter heating season. Several segments identified for testing or replacements are located along PG&E's backbone pipeline that brings gas from PG&E's interconnections with interstate pipelines in Southern California and, therefore, reduce capacity to serve customer load. Furthermore, the testing programs will continue over several years.

Accordingly, staff prepared a sensitivity case in the WGTM using Reference Case assumptions except for the following changes:

- The WGTM's function of expanding pipeline capacity is switched off for 2012 through 2016, inclusive.
- A portion of Northern California's natural gas pipeline capacity is assumed to be unavailable for several years.
    - PG&E's Baja backbone path capacity will be reduced by 300 MMcf/d from 1,138 MMcf/d to 838 MMcf/d for 2012 to 2016, inclusive.
    - PG&E's Redwood path capacity will be reduced by 200 MMcf/d from 2,150 MMcf/d to 1,950 MMcf/d for 2012 to 2016, inclusive.

At the time of the design of the Lowered Pipeline Pressure Case, the amount of capacity reductions used in the case were what was being implemented on the actual Redwood and Baja pipelines.

The additional sensitivity cases to widen the spread of natural gas prices, developed after the September 27, 2011, Joint Committee workshop on natural gas, are described in Chapter 5.

Electric Generation Input Assumptions Across Cases

Because electric generation is one of the major drivers of future changes to national and California natural gas demand, this section highlights how the electricity-related assumption changes discussed above ultimately affect the WGTM input assumptions for U.S. and California gas demand for electric generation. **Table 1** and **Table 2** highlight the electric generation resource mix assumed in each case. The power resource mixes are the result of the interactions of the specific judgmental changes staff made to issued-related key drivers of power resource mixes (for example, timing and magnitude of RPS targets, coal-fired power plant retirements). These power resource mix assumptions are inputs to the econometric analysis, which is exogenous to the WGTM and which calculates the electric generation sector gas demand, which are then input to the WGTM as independent variables.

Table 1: Highlights of United States Electric Generation-Related Input Assumptions for Cases Focused on Price

	Reference	High Gas Price	Low Gas Price	Constrained Shale
	2017			
Total US Electric Gen (GWh/yr)	4,496,631	4,514,224	4,486,367	4,496,631
Nuclear share of US Gen (% of Total)	18.5%	18.5%	18.5%	18.5%
Hydroelectric Share	5.8%	5.8%	5.8%	5.8%
Renewable Share	7.7%	6.4%	9.0%	7.7%
Fossil Share	68.0%	69.3%	66.7%	68.0%
US Gas Demand for Electric Generation (Tcf/yr)	8.3733	10.0276	8.1418	8.3733
	2022			
Total US Electric Gen (GWh/yr)	4,766,558	4,819,407	4,735,485	4,766,558
Nuclear share of US Gen (% of Total)	17.8%	17.8%	17.8%	17.8%
Hydroelectric Share	5.5%	5.4%	5.5%	5.5%
Renewable Share	9.9%	8.0%	11.1%	9.9%
Fossil Share	66.8%	68.8%	65.6%	66.8%
US Gas Demand for Electric Generation (Tcf/yr)	8.9663	11.7262	8.7017	8.9663
	2030			
Total US Electric Gen (GWh/yr)	5,179,648	5,309,049	5,102,910	5,179,648
Nuclear share of US Gen (% of Total)	16.7%	16.7%	16.7%	16.74
Hydroelectric Share	5.0%	4.9%	5.1%	5.0%
Renewable Share	11.9%	10.0%	12.4%	11.9%
Fossil Share	66.3%	68.4%	65.7%	66.3%
US Gas Demand for Electric Generation (Tcf/yr)	9.9367	12.8846	9.6993	9.9367

Source: California Energy Commission staff analysis.

Table 2: Highlights of California Electric Generation-Related Input Assumptions for Cases Focused on California Gas Demand Impacts

	Reference	High CA Gas Demand	Low CA Gas Demand
		2017	
Total CA Electric Gen (GWh/yr)	223,664	230,291	217,513
Nuclear Share	15.1%	14.7%	15.1%
Hydroelectric Share	12.2%	11.9%	12.6%
Renewable Share	25.1%	19.2%	26.3%
Fossil Share	47.6%	54.2%	44.7%
Gas Demand for Electric Generation (Tcf/yr)	0.6702	0.7489	0.6225
		2022	
Total CA Electric Gen (GWh/yr)	238,058	249,972	231,687
Nuclear Share	14.5%	10.9%	14.5%
Hydroelectric Share	11.5%	11.0%	11.8%
Renewable Share	29.4%	22.4%	34.1%
Fossil Share	44.5%	55.8%	38.6%
Gas Demand for Electric Generation (Tcf/yr)	0.6448	0.7833	0.5646
		2030	
Total CA Electric Gen (GWh/yr)	259,909	281,023	252,748
Nuclear Share	13.7%	0.0%	13.7%
Hydroelectric Share	10.5%	9.8%	10.8%
Renewable Share	28.7%	26.6%	38.8%
Fossil Share	47.1%	63.7%	35.5%
Gas Demand for Electric Generation (Tcf/yr)	0.7467	1.0474	0.5539

Source: California Energy Commission staff analysis.

The regression analysis that examined the relationship between historical trends in electric generation by fuel type and historical gas demand from electric generation yielded an equation that fits the historical data well. But the equation specifies only nuclear, conventional hydroelectric, other renewable (for example, wind, solar, geothermal, and biogas), and fossil fuel types. The form of this equation allowed staff to introduce specific input assumptions about the amount of future renewable, nuclear, hydroelectric, and fossil generation across cases.[11] These issue-relevant changes to inputs require staff judgment about the plausible range of future values of these key drivers. The reasons for the changes made are discussed above.

Natural gas, petroleum, and coal-fired generation are combined in a single variable, which is input to the econometric equation calculating gas demand by electric generation. The equation estimates how much of the total fossil generation is assigned to each fossil fuel type based on the relative costs of their fuels. A consequence of this approach is that changes in assumptions within the fossil fuel group (for example, retiring 50,000 MW of coal-fired power plants in the High Gas Price Case) are not highlighted in the tables.[12] Nevertheless, the effect is evident in the differences in gas demand for electric generation across the cases.

Table 1 focuses on the cases designed to explore how marketwide future gas prices might change under a variety of plausible future conditions. Therefore, the information highlighted in this table is at a national level. The information for the Reference Case and the Constrained Shale Gas cases are the same for two reasons. First, staff made no electricity demand-related changes to input assumptions between these cases: Changes were just about shale gas supply constraints and costs. Second, being input assumptions to the WGTM, these are the initial reference quantities and not the WGTM's final electric generation gas demand, which would be affected by assumptions about price elasticities of demand. United States electric generation gas demand most noticeably differs between the High Gas Price Case and the other cases, as this is the case that assumes significant amounts of retiring coal-fired generation, some of which the econometric model replaces with gas-fired generation.

Table 2 focuses on the cases designed to explore how California future gas demand might change under a variety of plausible future conditions. Since changes to assumptions that affect demand for electric generation by fuel type were made in both of these cases, the power resource mixes of both differ from that of the Reference Case. Notable differences include the share of generation from nuclear (especially in the High CA Gas Demand Case) and from renewable resources. The shares of conventional hydroelectric generation changes across cases only because the total generation amount changes across cases. The shares of fossil generation changes across cases because the total generation amount changes and because nuclear and renewable assumptions are changing, with fossil making up the difference.

11 The relationship of the four generation fuel types in the model is straightforward: The share of fossil generation is calculated by subtracting the sum of the hydroelectric, nuclear, and renewable share from the total amount of generation. Changing any of these shares automatically changes the fossil share.

12 Analysis illustrating an additional 40 GW of coal retirements are undertaken in Chapter 5.

Assumptions All Cases Share With the Reference Case

The following section discusses a few important assumptions that all cases share and have significant effects on the modeling results. Therefore, they are important to understand when interpreting and evaluating model results for all cases.

Price Elasticity of Demand

One of the most important set of assumptions included in the model is the price elasticity of demand for each class of natural gas end user. In simple terms, the price elasticity is a measure of how much demand for a product changes for a given change in price, and is usually expressed as a percentage. So a consumer with a price elasticity of -1 for natural gas will reduce the demand for natural gas by 1 percent for each 1 percent increase in natural gas price. This defines how price-responsive people and business are to fluctuations in the market for natural gas.

Price elasticity can result from numerous specific behaviors and responses to price change. The most common reactions to price increases are to cut back on whatever process is consuming the product (for example, adjusting the thermostat in your house to keep your house colder in the winter, thus using less natural gas) or to switch to some other product as a substitute. In the model, staff does not attempt to identify all of the underlying reasons for price adjustment. Instead, staff has relied on expert judgment and proprietary data to estimate the appropriate price elasticities.

Price elasticities can also vary depending on the time horizon chosen. Short-term price spikes or dips may have different effects than longer-term price levels. In the natural gas sector, economists typically find it necessary to distinguish between short- and long-term price elasticities. This is because participants in the market take different actions depending on what has happened to price in the recent past (this is sometimes called an *autoregressive feature* in the data).

The WGTM is able to allow for both immediate (one year or less) and longer term (more than one year) response to price. The short-run price elasticities are estimated from national data and shown in **Table 3.** From the same data, an estimate is made of how much participants weight the recent history or prices to determine their longer term choices. This estimate is called the half-life and is shown below. Finally, staff uses the estimates of short-term price elasticity and half-life to calculate long-term price elasticity, also shown in **Table 3**.

Table 3: Price Elasticity of Demand for Gas by Sector, All Cases

	United States			
	Residential	**Commercial**	**Industrial**	**Power Generation**
Price Elasticity (Short-Term)	-0.1475	-0.1218	-0.2201	-0.11860
Half-Life	2.1240	2.6721	3.5360	4.2980
Price Elasticity (Long-Term)	-0.5298	-0.5329	-1.2363	-0.7963

Source: Dr. Kenneth Medlock III, Appendix B.

A more complete explanation of this method, and the complete estimated gas demand equations are shown in the methodology slides in Appendix B. The price elasticity (short run) of natural gas demand in the power generation sector is -0.11860. The price elasticity assumptions shown in staff's April 19, 2011, workshop presentation have changed because the United States demand equations now used in the Reference Case have changed since that earlier vintage of the econometric analysis. For example, power generation sector gas demand elasticity had been -0.442 and is now -0.1186.

Part of the reason for updating the econometric demand formulation was improving the statistical methods used to capture time trends within the time series data. There were also improvements to the way the information about hydroelectric, nuclear, and renewable generation, including RPS and other non-RPS-eligible renewable generation (such as distributed renewable generation), were handled.

Allocating Statewide Estimated Gas Demand to Subareas

As described above, a regression analysis of state-level historical gas demand in each sector—residential, commercial, industrial, and electric generation—to derive equations used to project future statewide gas demand for each sector. But the statewide sector-specific gas demands have to be allocated to subareas to correspond to the WGTM gas market topology, which has a substate level of detail linking gas demand to gas supply areas by transmission facilities.

For states other than California, residential and commercial allocation factors are based on population weights of the defined regions within each state. County populations have been aggregated into regional populations and then used to calculate the region's population share within the state. For industrial and power generation, the weights are based on the location of gas-fired power plants within each state. The method for industry deviates in states such as Texas, where industrial load is particularly large. In Texas, the split of industrial demand is based on analysis of gas-using industry locations. The data sources are the United States Census and the Economic Census.

The substate allocation factors for California are calculated by a different method. They are based on historical gas demand by sector and subarea for 2009 reported in the *2010 California Gas Report*.

Table 4 shows the derived allocation factors used in this assessment. Staff's analysis assumes these allocation factors do not change over time in any sector.

Table 4: California Allocation Factors to Assign Statewide Sector-Specific Gas Demand to Geographic Subarea

CA-Central	CA-PG&E	CA-SoCal	
6.21%	32.86%	60.93%	Residential and Commercial
27.56%	30.27%	42.17%	Industrial and Power Generation

Source: California Energy Commission staff analysis of *2010 California Gas Report.*

CHAPTER 3: Modeling Results

Chapter 2 describes the role of each case within the overall study design and the assumptions and methods staff employed to construct them. This chapter discusses the highlights of the WGTM results for the cases. The case results are collectively discussed to indicate potential future vulnerabilities or opportunities related to activities in the natural gas and its related energy markets. After a brief description of where to find comprehensive results for each case, the following discussion of case results first focuses on price, then moves to supply, infrastructure, and finally demand-related issues such as cost and GHG emissions.

Detailed Results Available Online

Most of the highlighted results presented in this report are statewide, rather than by individual gas utility area. The exceptions include results about prices and the Lowered Pressure Case, which focused on the PG&E area. The entire set of WGTM results files—one for each case—is available on the Energy Commission's *2011 IEPR* website. Each result file includes complete WGTM results for worldwide, North America, United States total and individual states, California gas utility area, and power plant group area. These result files are in Microsoft Excel worksheet format and include tables of results extracted from the WGTM output files. Staff has created charts of results within these files, which help examine the results.

For easy reference, **Table 5** and **Table 6** provide "snapshots" of key input assumptions and WGTM results for 2022 and 2030. They are provided first as a roadmap to the different case assumptions and results, but being necessarily brief and not designed to tell the whole story, will not be fully clear without the results discussion that follows (or the assumptions discussion that precedes). The data results in the tables differ slightly compared to the similar tables posted in the draft report that was released prior to the Joint Committee Workshop on Natural Gas Market Assessment Reference Case and Scenarios of September 27, 2011. After the workshop, staff reviewed and revised some of the inputs and assumptions on the scenario cases, especially on the High CA Demand Case and the Low CA Demand Case. For example, before the revision, staff used the total electric production in the state as a basis to derive the RPS portion. However, after the revision, staff changed it to use the "qualified" electricity sales in the state.

Table 5: Summary of World Gas Trade Model Key Driver Assumptions and Model Results, 2022

	Reference Case	High Gas Price Case	Low Gas Price Case	Constrained Shale Case	High CA Gas Demand Case	Low CA Gas Demand Case	Lowered Pressure Case
Results in 2022							
DEMAND							
US Tcf/yr	25.30	25.05	25.92	24.15	25.10	25.16	25.21
US Gas-Fired Electricity Generation Tcf/yr	8.47	9.36	8.75	8.12	8.46	8.41	8.44
CA Tcf/yr	2.19	2.12	2.24	2.10	2.25	2.14	2.18
CA Gas-Fired Electricity Generation Tcf/yr	0.65	0.66	0.66	0.63	0.72	0.61	0.65
SUPPLY							
US Natural Gas Dry Production Tcf/yr	24.78	22.35	25.56	23.47	24.91	24.92	24.75
US Shale Tcf/yr	12.23	8.76	13.59	10.89	12.25	12.34	11.95
US LNG Tcf/yr	1.07	1.84	0.92	1.25	1.07	0.99	1.04
Canadian Imports Tcf/yr	3.48	4.53	3.64	3.04	3.32	3.30	3.28
Exports Tcf/yr	2.5	3.82	2.63	2.1	2.72	2.67	2.35
PIPELINE CAPACITY							
Cumulative New Capacity to CA (Tcf) (aggregated from 2010 to 2022)	0.08	0.12	0.06	0.09	0.41	0.07	0.09
Pipeline Utilization; % of total (EPNG+TW+MJ/ GTN/ KRGT/ Ruby)*	36.82/68.46/ 72.87/47.72	34.52/62.07/ 67.84/48.4	35.11/81.55/ 70.7/39.04	36.09/59.58/ 66.77/45.89	43.74/70.87/ 74.90/35.39	40.22/71.29/ 69.88/43.84	36.3/89.5/ 65.1/31.1
PRICES							
Price at Henry Hub ($2010)/MMBtu	5.63	5.98	4.94	5.96	$5.66	5.49	5.59
Basis to CA Border at Topock ($2010)/MMBtu	0.26	0.19	0.31	0.28	0.29	0.23	0.27
Basis to Malin ($2010)/ MMBtu	-0.08	-0.13	-0.03	-0.05	-0.05	-0.11	-0.06

*El Paso Natural Gas (EPNG) Transwestern (TW) Mojave (MJ) TransCanada Gas Transmission Northwest (GTN) Kern River Gas Transmission (KRGT) Ruby Pipeline (Ruby) CA (California)

Table 5: Summary of World Gas Trade Model Key Driver Assumptions and Model Results, 2022 (Continued)

	Reference Case	High Gas Price Case	Low Gas Price Case	Constrained Shale Case	High CA Gas Demand Case	Low CA Gas Demand Case	Lowered Pressure Case
Key Assumptions							
Average Annual GDP Growth Rate	2.6%	3.5%	2.1%	2.6%	2.6%	2.6%	2.6%
Gas Technology Improvement Average Annual Growth Rate	1%	1%	1%	1%	1%	1%	1%
Total US Electricity Production (GWh)	4,766,558	4,819,407	4,735,485	4,766,558	4,770,521	4,761,241	4,766,558
US Electricity Resource Mix (% of total from Fossil/Nuclear/Hydro/Renew)	66.8/17.8/ 5.45/15.37	68.8/17.8/5.4/ 13.4	65.6/17.8/ 5.5/16.6	66.8/17.8/ 5.45/15.37	67.2/17.7/5.5/15.2	66.6/17.8/5.5/15.6	66.8/17.8/ 5.45/15.37
Total CA Electricity Production (GWh)	238,058	240,698	236,506	238,058	242,021	232,741	238,058
CA Electricity Resource Mix (% of total from Fossil/Nuclear/Hydro/Renew)	44.5/14.5/ 11.5/29.4	45.0/14.5/ 11.4/29.1	44.3/14.5/ 11.6/29.6	44.5/14.5/ 11.5/29.4	51.6/11.3/11.3/25.8	38.7/14.5/11.8/35.0	44.5/14.5/ 11.5/29.4
When CA Meets Maximum RPS Target	On Time	On Time	On Time	On Time	2030	On Time[4]	On Time
When Other States Meet Individual Maximum RPS Targets	5 yrs late	10 yrs late	On Time	5 yrs late	5 yrs late	5 yrs late	On Time
Additional US Coal Generation Converts to Natural Gas	0	50 GW	0	0	0	0	0
Constrain/Augment Natural Gas Resources							
US	NY	PA, NY, CO and WY	Upper End of Range	NY	NY	NY	NY
World	IIV enters marker in 2020[2]	IIRV Constrained[1]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]
LNG Exports	Allowed but not imposed	Imposed LNG Exports	Allowed but not imposed	Allowed but not imposed	Allowed but not imposed	Allowed but not imposed	Allowed but not imposed
Pipeline Capacity Additions (Model feature turned On/Off)	ON	ON	ON	ON	ON	ON	OFF[3]
PG&E Backbone Capacity Reduction Constraint, MMcf/d	None	None	None	None	None	None	300 on Baja/200 on Redwood
Additional Environmental Mitigation Cost ($2005/Mcf)	N/A	$0.40/Mcf shale $0.20/Mcf Conv	N/A	$0.40/Mcf shale $0.20/Mcf Conv	N/A	N/A	N/A

Source: California Energy Commission staff analysis
1 Note: IIRV refers to Iran, Iraq, Russia, and Venezuela.
2 Note: IIV refers to Iran, Iraq, and Venezuela.
3 Note: Capacity additions off for years 2012-2016.
4 Note: In this case, continues to grow to 40 percent by 2027 and then stabilizes.

Table 6: Summary of World Gas Trade Model Key Driver Assumptions and Model Results, 2030

	Reference Case	High Gas Price Case	Low Gas Price Case	Constrained Shale Case	High CA Gas Demand Case	Low CA Gas Demand Case	Lowered Pressure Case
Results in 2030							
DEMAND							
US Tcf/yr	27.58	27.82	29.22	26.81	27.58	27.48	27.79
US Gas-Fired Electricity Generation Tcf/yr	9.47	10.97	9.91	9.23	9.47	9.37	9.54
CA Tcf/yr	2.31	2.25	2.45	2.24	2.48	2.20	2.32
CA Gas-Fired Electricity Generation Tcf/yr	0.66	0.69	0.69	0.64	0.80	0.54	0.66
SUPPLY							
US Natural Gas Dry Production Tcf/yr	25.85	24.18	28.11	25.01	26.43	26.27	26.23
US Shale Tcf/yr	13.44	10.79	16.33	13.05	14.10	13.97	13.89
US LNG Tcf/yr	1.17	1.89	0.99	1.45	1.17	1.12	1.12
Canadian Imports Tcf/yr	4.70	5.24	4.42	3.91	4.42	4.49	4.37
Exports Tcf/yr	2.66	3.65	2.68	2.2	2.87	2.78	2.41
PIPELINE CAPACITY							
Cumulative New Capacity to CA (Tcf) (aggregated from 2010 to 2030)	0.19	0.12	0.25	0.16	0.69	0.15	0.23
Pipeline Utilization; % of total (EPNG+TW+MJ/ GTN/ KRGT/ Ruby)*	35.8/92.3/ 66.3/28.3	34.9/80.5/ 61.0/33.3	37.1/95.1/ 70.7/30.4	35.5/80.9/ 64.4/33.6	40.14/97.56/ 70.94/48.63	39.57/86.99/ 62.11/28.77	36.3/89.5/ 65.1/31.1
PRICES							
Price at Henry Hub ($2010)/ MMBtu	5.97	6.65	5.20	6.21	6.03	5.91	5.90
Basis to CA Border at Topock ($2010)/MMBtu	0.27	0.26	0.14	0.40	0.35	0.28	0.31
Basis to Malin ($2010)/MMBtu	-0.14	-0.13	-0.22	0.00	-0.05	-0.11	-0.08

*El Paso Natural Gas (EPNG) Transwestern (TW) Mojave (MJ) TransCanada Gas Transmission Northwest (GTN) Kern River Gas Transmission (KRGT) Ruby Pipeline (Ruby) CA (California)

Table 6: Summary of World Gas Trade Model Key Driver Assumptions and Model Results, 2030 (Continued)

	Reference Case	High Gas Price Case	Low Gas Price Case	Constrained Shale Case	High CA Gas Demand Case	Low CA Gas Demand Case	Lowered Pressure Case
Key Assumptions							
Average Annual GDP Growth Rate	2.6%	3.5%	2.1%	2.6%	2.6%	2.6%	2.6%
Gas Technology Average Annual Growth Rate	1%	1%	1%	1%	1%	1%	1%
Total US Electricity Production (GWh)	5,179,648	5,309,049	5,102,910	5,179,648	5,184,835	5,170,859	5,179,648
US Electricity Resource Mix (% of total from Fossil/Nuclear/Hydro/Renew)	66.3/16.7/ 5.0/17.0	68.4/16.7/ 4.9/14.9	65.7/16.7/ 5.1/17.5	66.3/16.7/ 5.0/17.0	66.8/16.0/ 5.0/17.2	65.8/16.8/5.0/17.5	66.3/16.7/5.0/17.0
Total CA Electricity Production (GWh)	259,909	266,402	256,059	259,909	265,096	251,119	259,909
CA Electricity Resource Mix (% of total from Fossil/Nuclear/Hydro/Renew)	47.1/13.7/ 10.5/28.7	48.0/13.7/ 10.3/28.0	46.5/13.7/ 10.7/29.2	47.1/13.7/ 10.5/28.7	56.7/0.0/ 10.3/33.0	35.4/13.7/ 10.9/40.0	47.1/13.7/10.5/28.7
When CA Meets Maximum RPS Target	On Time	On Time	On Time	On Time	2030	On Time[4]	On Time
When Other States Meet Individual Maximum RPS Targets	5 yrs late	10 yrs late	On Time	5 yrs late	5 yrs late	5 yrs late	On Time
Additional US Coal Generation Converts to Natural Gas	0	50 GW	0	0	0	0	0
Constrain/Augment Natural Gas Resources							
US	NY	PA, NY, CO and WY	Upper End of Range	NY	NY	NY	NY
World	IIV enters marker in 2020[2]	IIRV Constrained[1]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]
LNG Exports	Allowed but not imposed	Imposed LNG Exports	Allowed but not imposed	Allowed but not imposed	Allowed but not imposed	Allowed but not imposed	Allowed but not imposed
Pipeline Capacity Additions (Model feature turned On/Off)	ON	ON	ON	ON	ON	ON	OFF[3]
PG&E Backbone Capacity Reduction Constraint, MMcf/d	None	None	None	None	None	None	300 on Baja/200 on Redwood
Additional Environmental Mitigation Cost ($2005/Mcf)	N/A	$0.40/Mcf shale $0.20/Mcf Conv	N/A	$0.40/Mcf shale $0.20/Mcf Conv	N/A	N/A	N/A

Source: California Energy Commission staff analysis.
1. Note: IIRV refers to Iran, Iraq, Russia, and Venezuela.
2. Note: IIV refers to Iran, Iraq, and Venezuela.
3. Note: Capacity additions off for 2012-2016.
4. Note: IN this case, continues to grow to 40 percent by 2027 and then stabilizes.

Price-Related Modeling Results

Future natural gas prices matter to everyone in the market, from the producers who receive them to the consumers who pay them. The uncertainties affecting any attempt to accurately predict future gas prices flows through to producers' predictions of their future revenues and profit as well as to consumers' predictions of their future gas bills. Future gas prices also matter to policy makers and regulators who have to weigh the potential future tradeoffs that current and proposed policies might produce. An assumption about the future price of natural gas is typically a part of complex analyses that try to balance sometimes competing effects on public health and safety, the environment, and a thriving economy, which requires adequate, reliable and affordable energy supplies. This wide interest in price is why the discussion of results begins with the price-related ones.

The WGTM produces natural gas prices for the Henry Hub, California border locations, and citygate locations inside California. The California citygate locations of interest are the PG&E Citygate (Hub: US-PG&E), the SoCal Gas Citygate location (Hub: US-SoCalGas), and the SDG&E Citygate price location (Hub: US-SDG&E). These citygate locations are a direct output of the model and do not require any post processing. Also, the citygate prices from the model have transportation costs included (up to the citygate location). End-use prices of natural gas are calculated outside the model and are discussed in Chapter 4. Even though they are WGTM results, citygate prices are saved for Chapter 4 because they are the starting point for many of the end-use natural gas price calculations.

The WGTM's input assumptions and outputs about prices are not in current year dollars but in real $2005. When staff reports a result in real $2010, the model result has been converted based on historically observed inflation between those years. Most price results in this report are presented in real $2010. Future inflation expectations would have to be added to increase the real $2010 results into future year then-current (nominal) dollars to allow results to be compared directly to price or cost estimates made by others, either in nominal dollars or in real dollars other than $2010. Both real and nominal price results are provided for some outputs in the results worksheets mentioned above. The inflation series, for observed past years and future year estimates, are also included in Appendix G.

Henry Hub Annual Average Spot Prices

The spot purchase price of natural gas at the Louisiana trading hub called Henry Hub is a nationally important market price benchmark. Currently, natural gas prices at Henry Hub are in the low $2/MMBtu range. Spot prices of natural gas reflect a large supply from shale natural gas and a slow economy. Much of the natural gas production is occurring on leased land where many gas developers must drill for gas soon or lose their lease. Since demand is low due to the recession, the resulting temporary oversupply situation pushes current market prices down.

What useful information can the modeling results give about future Henry Hub spot market prices? As described in Chapter 2, in addition to the business as usual Reference Case, staff constructed three other cases to provide information about what gas market prices may be under a variety of plausible future conditions, focusing on key drivers with effects large enough to move price nationally and which have considerable uncertainty: the High Gas Price Case, the Constrained Shale Gas Case, the Low Gas Price Case.

Explanation of Model's Early Price Results Through 2014

To fully understand the model's series of price results, an explanation of the early years of the simulation is helpful. The model begins computing results in 2005, using historical data for some key drivers up through 2008 to 2010, depending on the availability of the data. When historical data is not available, assumptions about future conditions are made, generally projecting historical averages into the future. The volatility seen in the model's price results between 2005 and 2010 is in part an artifact of using actual historical data rather than averages of historical data, which would tend to smooth out results.[13] For example, the 2008 model output shows natural gas prices spiking at over $8.50/MMBtu (in real 2010 dollars). Factors contributing to this result include:

- The model has an econometric component, which contains a crude oil/natural gas price relationship. The historically high oil prices in 2008, which are reflected in the inputs, helped pull up natural gas prices in the model.
- United States hydroelectric generation in 2007 and 2008 was lower than in previous years, increasing natural gas demand by electric generators, where they were the marginal electricity supply.
- United States total electricity generation demand increased in 2007, dropping only slightly in 2008, again affecting gas demand for electric generation natural gas prices.

Similarly, natural gas prices dropped significantly in the 2009 to 2010 portion of this historical simulation period, in part due to the effects of the recession that started at the end of 2008 and so reduced the GDP growth assumptions made in the simulation years 2009 and 2010. Another historical input assumption resulting in lower price in the 2009 to 2011 period of the simulation is the growing historical production from unconventional gas resources that were beginning to be observed at the time, partially attributable to technological advancements in hydraulic fracturing.

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13 For most of this period, namely 2014 – 2030, prices do not vary much. Many key indicator model inputs assume historical averages or are projected with little to no variation. Three key indicators of interest where averages are assumed: United States hydro generation, United States GDP growth, and United States cooling degree days. United States fossil generation, which is calculated as total electricity production minus United States hydroelectric generation, nuclear generation, and other renewable generation, shows virtually no volatility after 2010 in the Reference Case. This also helps explain the lack of volatility in the model output natural gas prices.

The significant upswing in natural gas prices in 2012 and 2013, when the prices of natural gas jump from the $4/MMBtu range to the $8/MMBtu range, occurs after the simulation period when historical input assumptions are used. So, the shift from historical inputs to input assumptions generally based on historical averages explains some of the upswing. For one, the economy is assumed to be improving, driving up gas demand (and prices, as demand is satisfied at higher levels of the supply curve).[14]

Another technical feature of the model is also contributing to rising prices in this early simulation period. The nature of the investment logic in the model can help explain this large price bump in the 2011 – 2013 period, and the price drop that follows in 2014. The WGTM model uses natural gas production forecasts, based on historical production, for 2005 through 2011. It accepts what investments have been made historically in determining the amount of proved gas reserves[15] and the amount of gas being produced. At this point in the simulation, 2012, the model takes over the internal decisions to invest in new natural gas infrastructure in response to increasing demand and the assumed marginal supply curve of gas resources. The investment logic in the model assumes the amount of natural gas production starts at zero in 2012. The model then must prove up natural gas resources to be in line with the historically based forecast.[16] While the model is proving up these natural gas reserves, through drilling and well development, a price surge occurs in 2012 and 2013. In 2014, there is a natural gas price drop of about $1/MMBtu; this is a result of all the natural gas reserves that the model proved up starting in 2012. This is a technical issue with the model that staff is looking into.

Energy Commission staff is looking at some potential actions to remedy the rapid price increase and decline in 2011 – 2014. One potential solution is to put an initial resource number in for 2012 or bump up the natural gas production forecast number in 2012 to more accurately reflect the natural gas resource base. Another potential solution is to report natural gas prices in five-year increments, which would smooth out the data.

Shale is projected to be the primary source of natural gas for the next 10 years and beyond. If shale gas production is restricted more or has higher environmental compliance costs than assumed in the Reference Case, then staff would expect to see higher natural gas prices as a

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14 Another feature of the modeling that could contribute to the natural gas price drop in 2014 is the release of a constraining assumption in the simulation: The model allows LNG exports from Australia to commence in 2014. For more on Australian LNG exports, see: http://www.arcticgas.gov/Deloitte-forecasts-U.S.-natural-gas-prices-above-$8-by-2022.

15 Proved gas reserves refers to the quantities of natural gas that current analysis of geologic and engineering data demonstrate with reasonable certainty (normally 90 percent or greater) to be recoverable in the future from known gas reservoirs under existing economic and operating conditions.

16 "Proving up" natural gas reserves is the process of spending capital dollars to convert probable and possible reserves (located in the earth's subsurface) into proved reserves. In the WGTM, the investment logic simulates this phenomenon.

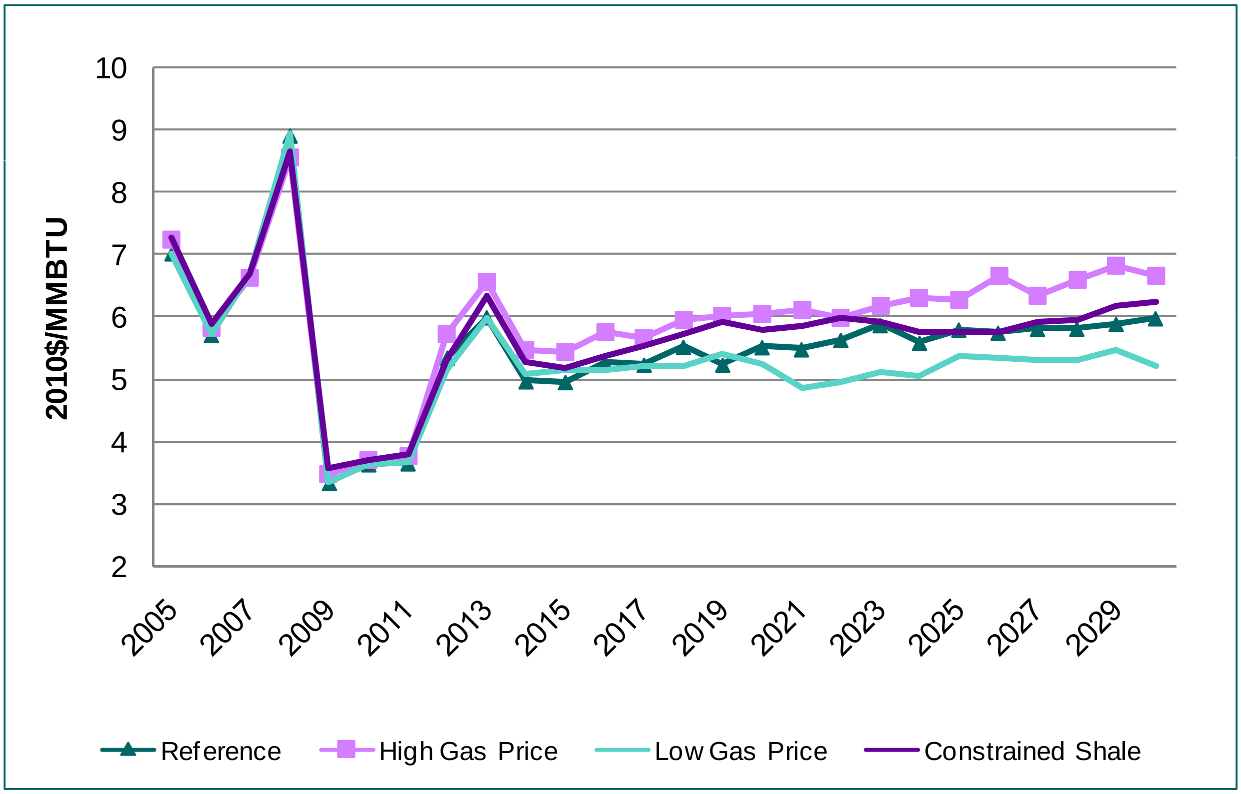
result. Indeed, the Constrained Shale Gas Case Henry Hub prices results show that. The restrictions and additional environmental costs imposed on this case could be either more or less severe than the assumptions. This is a significant source of uncertainty about future gas prices.

The Henry Hub annual average spot price in the High Gas Price Case reaches $6.00/MMBtu by 2018 (12 years before the Reference Case hits that mark) and by 2030 has somewhat leveled off below $6.80/MMBtu (in $2010).

The Low Gas Price case actually yields a Henry Hub gas price slightly higher than the Reference Case in 2019. Surprising results like this may occur due to the timing of investments. Looking past 2019, the Low Price Case's Henry Hub prices hover around $5.00/MMBtu through 2024, increasing to about $5.30/MMBtu afterward.

Since California imports more than 87 percent of its natural gas supply from out-of-state, natural gas California border and citygate prices follow the same general trends as the Henry Hub price. Figures of these conditionally estimated prices will be provided in Chapter 4. **Figure 4** does not show the price of natural gas for the High and Low CA Demand cases; prices in these cases do not differ much from the Reference Case and thus do not provide much useful information. California is a relatively small piece of the United States natural gas market; it does not have the market power to significantly affect the price of natural gas. However, events outside California can influence the price Californians pay for natural gas. It is also likely that if the price of natural gas changes at a major market hub outside California, such as the Henry Hub, the price Californians pay will change as well.

Figure 4: Henry Hub Prices for Selected Cases



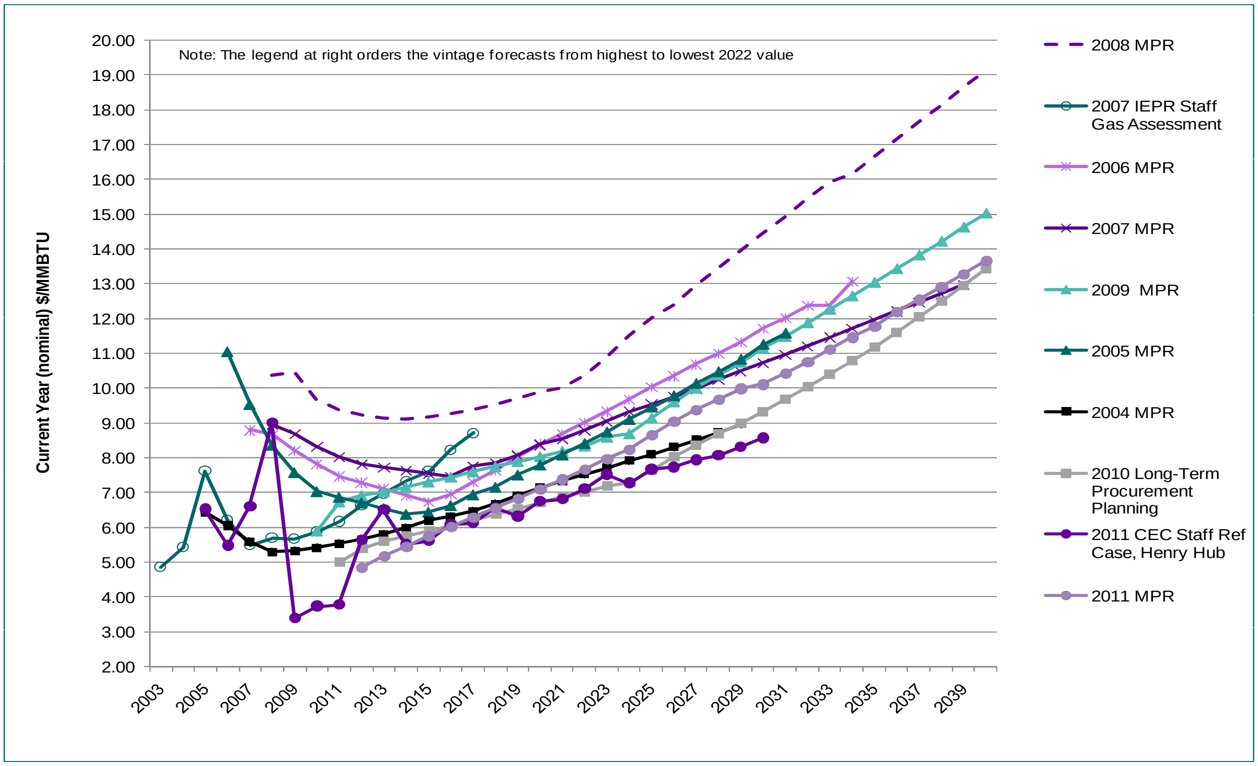
Source: California Energy Commission staff analysis.

Estimates of future annual average natural gas spot purchase prices at Henry Hub are used by California energy and environmental agencies both to analyze the potential effects of proposed policies and to implement existing policies. For example, when implementing the RPS for investor-owned utilities, the CPUC has directed parties to use a Henry Hub spot gas price forecast as an input to calculating the so-called *Market Price Referent* (MPR). The MPR is an estimate of the future cost of electricity, assuming the electricity is generated by a gas-fired power plant, California's marginal electricity source. This natural gas-based electricity price has been used as a reasonableness benchmark for the actual prices being bid by renewable generators into the RPS-competitive solicitations for power purchase agreements.

As expectations of future gas prices change over the years, so too has the reasonableness benchmark for renewable generation bid prices. **Figure 5** shows how the CPUC-directed assumptions about future Henry Hub spot gas prices have changed dramatically between 2004 and 2009. Although no MPR was calculated in 2010, the CPUC directed the same method be used to develop a future gas price assumption for analysis conducted in the

Long-Term Procurement Planning (LTPP) proceeding.[17] The 2010 LTPP assumptions for future Henry Hub prices are also shown in **Figure 5**, as is staff's Reference Case result.

Figure 5: Historical Estimates of Annual Average Henry Hub Natural Gas Spot Purchase Price Used as Assumptions in California Energy Regulatory Activities



Sources: Reference Case (Energy Commission staff analysis); 2010 LTPP (E3: Energy + Environmental Economics, April 2011 Evaluation Metric Calculator at http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/LTPP2010/LTPP_System_Plans.htm. Market Price Referent (MPR) forecasts (E3: Energy + Environmental Economics, Public Projects website at http://www.ethree.com/public_projects/cpuc3.htm.

Expectations of future gas prices made between 2004 and 2008 generally increased year over forecast year. After 2008, expectations started going downward year over forecast year as they began to incorporate significant, if unexpected, events such as the impact of a severe recession on demand and major technological developments in shale gas extraction.

Recent changes to the way the RPS program is implemented may no longer require the MPR benchmark to be calculated. However, it seems inescapable that expectations of future

17 The CPUC's Long-Term Procurement Proceeding process for investor-owned electric utilities employs a long-term gas price forecast in comparative performance analyses of alternative resource plans, leading to decisions on, among other things, electric capacity and energy and natural gas procurement limits.

natural gas prices will continue to play some important role in energy and climate change policy analysis and policy program implementation, at least as long as gas-fired generation is the marginal source and a general avoided cost approach is built into the cost-effectiveness analyses of planning studies and new regulation rulemaking, or into the detailed mechanisms employed to implement adopted programs. For example, programs providing incentives for distributed renewable generation and combined heat and power facilities by setting fixed feed-in tariffs (or by otherwise establishing price terms of power purchase agreements, which may require reasonableness checks) are likely to incorporate into their programs a then-current expectation of future gas prices.

Whatever the purpose to which a then-current expectation of future gas prices is put, the message of **Figure 5** is clear: Expectations can change quickly and dramatically as the next round of expectations takes into account the events that have just occurred and considers the apparent new trends in motion. The more complex and uncertain the system is about which expectations (assumptions) for the future are being developed, the more careful the user of these expectations (assumptions) must be if acting on them. There are simply limits to how accurate expectations can be.

Using Futures Prices as a Forecast

A *futures price* is a price set by a number of buyers and sellers that is agreed to today for the purchase of gas to be delivered in the future. However, less than 1 percent of all natural gas futures contracts are ultimately held for physical delivery.[18]

The fact that so few futures contracts are tied to physical deliveries tells staff that many times these contracts may be used for other purposes such as price hedging. The price paid today for natural gas may be different than it is three months from now. Futures pricing makes use of private knowledge today about what may influence the price in the future. For example, three months from now supply, demand, or government policy situations may change from what they are today. When using futures as a forecast, one needs to determine what day to use for a futures contract. For example, a futures contract for delivery of natural gas in March of a given year can be purchased any business day in the preceding February, or the month before that, and so on. Does a forecaster use the 15th day of every month, an average of trading days, or some of the trading days during bid week?[19] In addition, the forecaster must accept whatever assumptions the traders made, without knowing what those assumptions are. If the purpose of a forecast is to gain insights about the market based on various assumptions made by the forecaster, then futures prices leave the forecaster (and

18 See page 7 of http://www.ngsa.org/assets/Docs/Issues/19a%20-%20US%20Natural%20Gas%20Market%20Transparency%20Study%20by%20Albrecht.pdf.

19 *Bid week* refers to the last five business days of a month. During bid week, buyers and sellers arrange for the purchase and sale of natural gas to be delivered throughout the coming month.

the consumers of the forecast) in the dark, as the assumptions that were made (by the traders) are not knowable.

Another aspect to think about is that most futures transactions take place within the first few years of the tradable horizon for a given contract. There are few buyers and sellers trading futures contracts many years out into the future. But, in fact, Henry Hub Natural Gas Futures are listed for the current year and the next 12 years.[20] If a long-term forecast is the goal, the futures market may not provide a large enough sample size of the market to accurately predict market interactions far into the future. Also, the further out into the future, the more uncertainty surrounds assumptions about the economy, policy decisions, and other factors that affect the price of natural gas. In the short run, the futures price of natural gas may be an adequate forecast, but for terms spanning more than a few years, futures market natural gas prices may not be a good gas price forecast.

Using *futures prices* as a forecast has been discussed and used by many industry stakeholders, including government policy makers. There are pros and cons to using futures prices as a forecast. One reason for using futures prices is that many people assert that there is no good forecast, so using futures prices will deviate as much as the rest of the market. In theory, futures prices summarize privately available information about the supply and demand of natural gas. There are a number of economists who believe that futures natural gas prices make an accurate price forecast. Lawrence Berkeley National Laboratory (LBNL) researchers performed a study comparing futures natural gas prices to the U.S. EIA's *Short-Term Energy Outlook* (*STEO*).[21] These researchers found that the futures prices were closer to spot prices than the *STEO*, which uses an economic model. The time frame examined in the LBNL study was up to 24 months in the future. Other analysts compared the U.S. EIA's *Annual Energy Outlook 2010* (*AEO 2010*) reference case projection of Henry Hub gas prices to the New York Mercantile Exchange (NYMEX) natural gas futures strip and found that, from 2009 through 2020, both prices were very similar with the NYMEX prices at a slight premium to the *AEO* forecast.[22]

There is also a method known as "blending" where the first few years of futures prices are used, and then the results of a natural gas model are blended with the futures to get a long-term forecast. This "blended" forecast was adopted by the Energy Commission in the *2005 IEPR* proceeding but not in the following *IEPR* proceedings afterward. The CPUC has used a blended natural gas price forecast to estimate an electricity MPR that, in turn, has been

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20 See http://www.cmegroup.com/trading/energy/natural-gas/natural-gas_contract_specifications.html, and http://www.cmegroup.com/rulebook/NYMEX/2/220.pdf.

21 See Wong-Parodi, G. (2005). *Comparing Price Forecast Accuracy of Natural Gas Models and Futures Markets*.

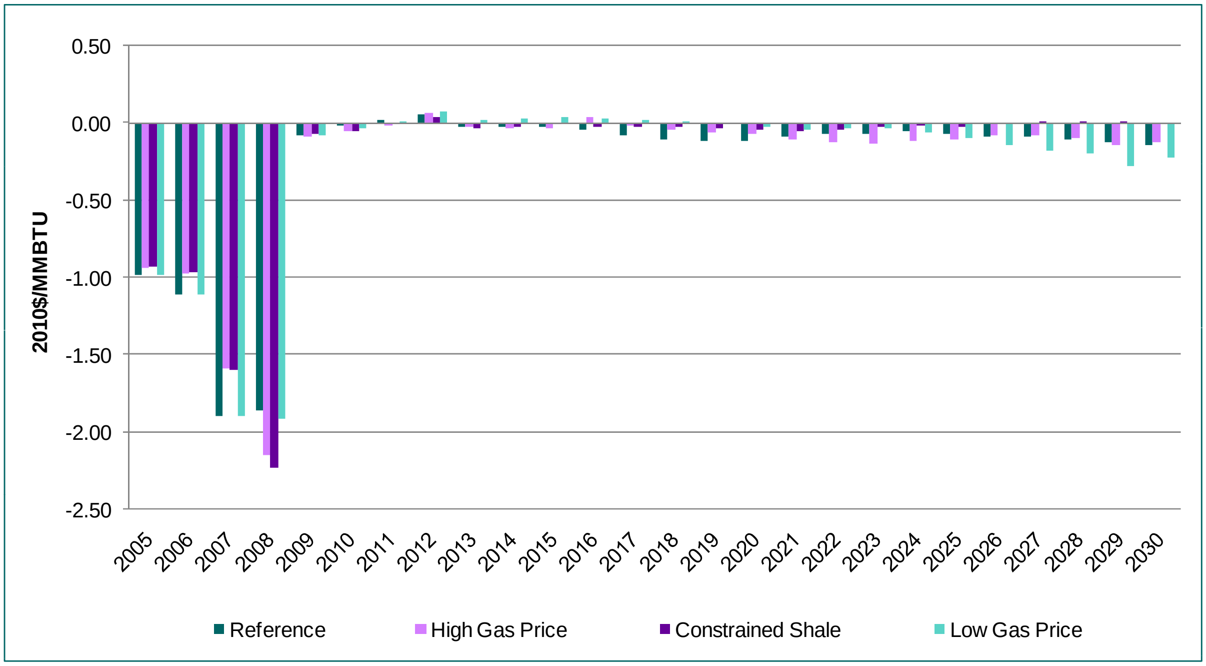
22 See Bolinger, M. and R. Wiser (2010). *Comparison of AEO 2010 Natural Gas Price Forecasts to NYMEX Futures Prices*. Ernest Orlando, Lawrence Berkeley National Laboratory. Retrieved from http://eetd.lbl.gov/ea/emp/reports/53587_memo.pdf.

used as long-term price benchmark for acquiring renewable energy generation to comply with the Renewable Portfolio Standards (RPS) obligations.

Basis Differentials

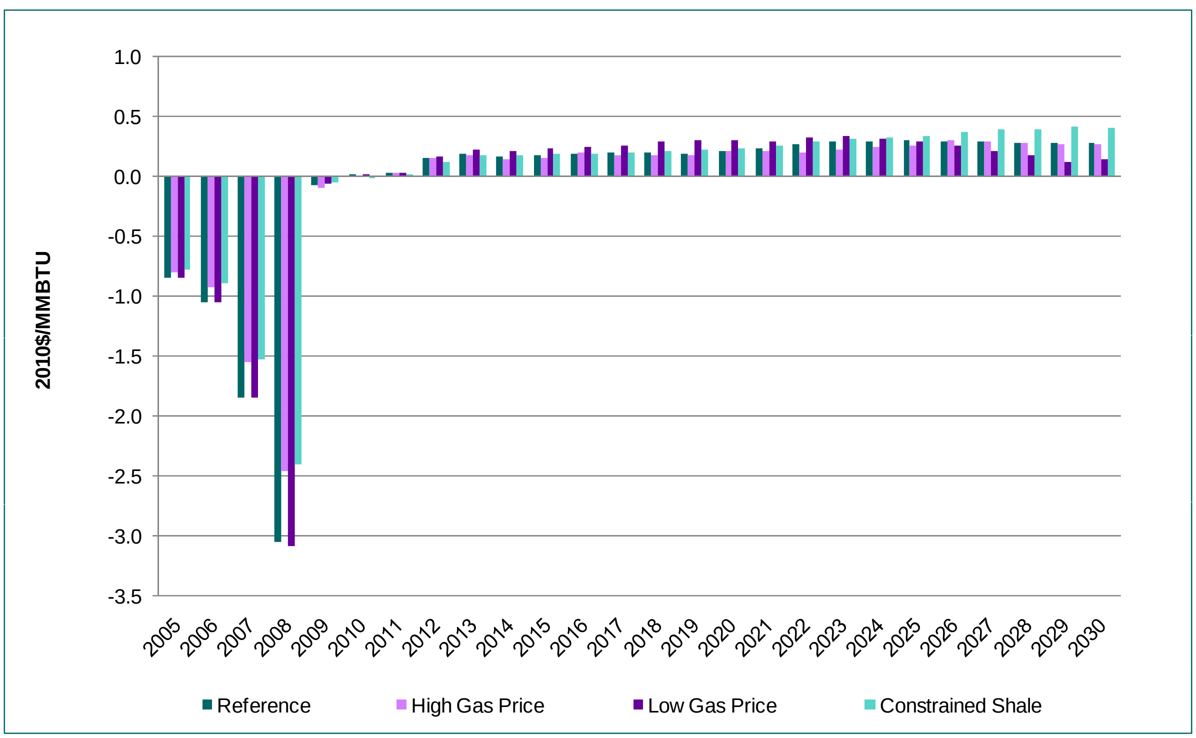
A *basis differential* is the difference in the price of natural gas at two different pricing locations. It is a measure of the value of having transportation options available to you that can access the cheapest supplies of natural gas and deliver them for your use. For simplicity, staff assumes a basis differential is the difference from a natural gas pricing point and the Henry Hub pricing point (point of interest minus Henry Hub). **Figure 6** and **Figure 7** represent the basis differentials for Malin and SoCal Border hub prices relative to Henry Hub. Looking at **Figure 7**, which shows the basis differential between the Malin pricing point and the Henry Hub pricing point, the basis differential shrinks greatly starting in 2010 – 2011. This means natural gas at the Malin hub is becoming relatively cheaper compared to the Henry Hub. First, the Ruby Pipeline, which brings natural gas to Malin from Wyoming, came into service in 2011; this creates more gas on gas competition with Henry Hub. The Ruby Pipeline gives the Malin location another source from which to receive gas. Secondly, with all the shale gas coming to market, staff expects prices of natural gas at various pricing hubs to shift as shale supplies change in different market areas. Also, the Rocky Mountain Express Pipeline (REX), which carries natural gas east from Colorado to Wyoming, played a role in causing California natural gas prices to increase toward Henry Hub prices. In the Low Gas Price Case in **Figure 6**, the basis differential remains larger than the other cases in 2026 through 2030; this means Henry Hub prices are relatively higher than Malin prices of natural gas. In the Low Gas Price Case, more gas flows through the Ruby Pipeline to Malin than in the other cases, which gives Malin more supply options, making its price of natural gas relatively cheaper than Henry Hub.

Figure 6: Malin Basis Differential to Henry Hub (Malin – Henry Hub)



Source: California Energy Commission staff analysis.

Figure 7: SoCal Border (Topock) Basis Differential to Henry Hub (Topock – Henry Hub)



Source: California Energy Commission staff analysis.

Figure 7 shows the basis differential between the SoCal Border (Topock) and the Henry Hub. **Figure 7** shows essentially the same story as in **Figure 6**; more shale gas coming to market causes more gas-on-gas competition and changes in shale supply. In **Figure 7**, the Constrained Shale Gas Case, staff's assumption is that the cost of producing shale gas becomes $0.20 more expensive than conventional gas; this means there is less shale to meet market demand, and the market demand will be met by more expensive conventional gas sources. Looking at the Constrained Shale Gas Case for 2026 through 2030, staff sees the SoCal Border price of natural gas become more expensive than Henry Hub relative to all the other cases.

Looking at **Figure 6** and **Figure 7,** SoCal Border (Topock) prices increase more relative to Henry Hub than do Malin prices. This can be explained by the fact that Malin can receive natural gas from the north (Canada) and the south (Gulf Coast), which increases gas-on-gas competition and puts downward pressure on prices of natural gas, whereas Topock has fewer supply options. No basis differentials were computed for citygate price locations because citygate prices of natural gas already have some intrastate pipeline rates included in them, whereas Henry Hub prices do not.

Although citygate prices are outputs of the WGTM, they are discussed in Chapter 4, being the starting point for many end-user gas prices.

Supply-Related Modeling Results

This section highlights selected supply-related modeling results across the cases. **Table** 7 and **Table 8** show the annual average production volumes for each case for both United States gas production from all sources and United States gas production from just shale formations, respectively. To further compare the cases, **Figure 8** and **Figure 9** highlight the differences of production in each case from the Reference Case and each other. For selected snapshot years 2020 and 2030, additional tables show how the results for United States production, shale production, and California production in selected cases differ from the Reference Case as a percentage.

The discussion in this section focuses on the Reference Case and the changed cases that were designed to move gas market prices: the High and Low Gas Price, and Constrained Shale Gas Cases.

Table 7: United States Natural Gas Production Summary, MMcf/d

Year	Reference	High Gas Price	Low Gas Price	Constrained Shale	High CA Demand	Low CA Demand
2005	48,330	48,154	48,330	48,000	48,330	48,330
2006	51,269	50,707	51,269	50,410	51,269	51,269
2007	53,443	53,116	53,443	52,859	53,443	53,443
2008	55,821	55,295	55,821	55,209	55,811	55,817
2009	58,352	57,457	58,354	57,157	58,453	58,376
2010	59,606	58,727	59,581	58,431	59,599	59,614
2011	62,403	61,402	62,444	61,030	62,400	62,426
2012	61,126	58,965	63,060	60,323	62,065	61,345
2013	60,853	56,817	62,574	59,080	61,742	60,843
2014	61,494	55,594	62,618	58,711	61,573	61,722
2015	62,229	55,400	62,505	58,577	61,993	62,686
2016	62,656	55,574	63,124	59,382	62,843	63,380
2017	63,063	56,225	64,300	60,184	63,580	64,035
2018	63,916	57,254	65,336	60,644	64,513	64,951
2019	64,709	57,792	66,318	61,175	65,696	65,642
2020	65,896	58,580	67,437	61,978	66,475	66,488
2021	66,920	59,745	68,906	63,212	67,459	66,891
2022	67,883	61,238	70,029	64,301	68,246	67,226
2023	68,515	62,620	71,019	65,229	68,344	68,118
2024	69,020	63,298	71,907	66,745	69,088	69,386
2025	69,635	63,562	72,329	67,650	70,080	69,980
2026	69,976	64,289	72,573	68,258	70,633	70,144
2027	70,075	65,214	73,036	68,627	71,387	70,522
2028	70,461	65,735	73,934	68,620	71,937	70,441
2029	70,782	65,642	74,919	68,476	72,004	70,760
2030	70,826	66,256	77,020	68,526	72,407	72,064

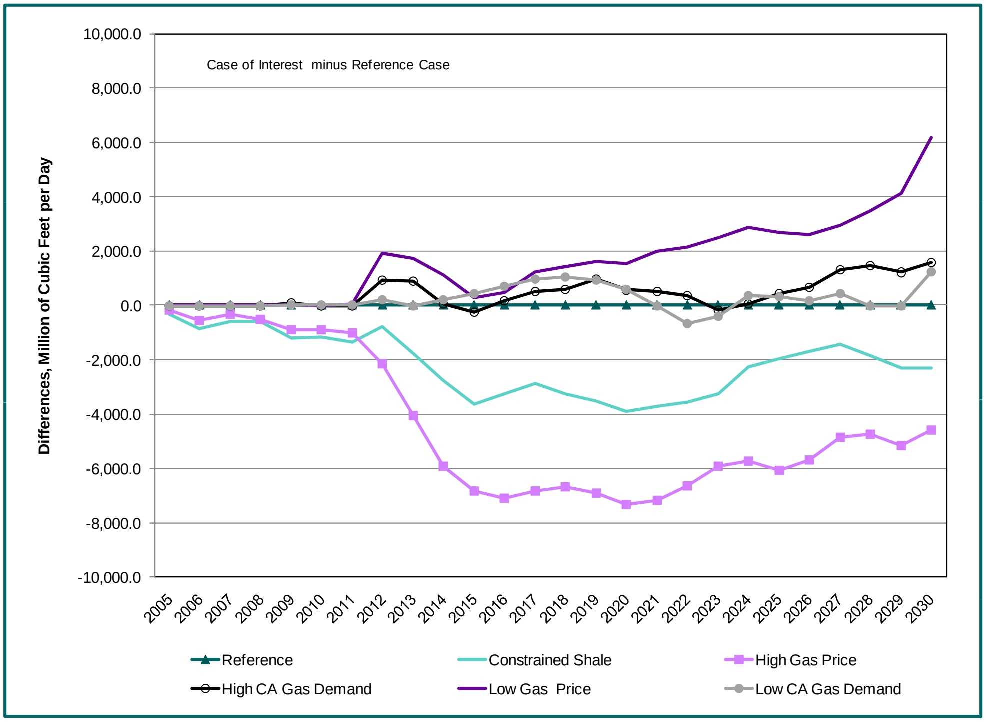
Source: California Energy Commission staff draft analysis.

Table 8: United States Shale Gas Production Summary, MMcf/d

Year	Reference	High Gas Price	Low Gas Price	Constrained Shale	High CA Demand	Low CA Demand
2005	1,027	1,027	1,027	1,027	1,027	1,027
2006	1,794	1,788	1,794	1,791	1,794	1,794
2007	3,479	3,438	3,479	3,453	3,479	3,479
2008	5,750	5,655	5,750	5,676	5,748	5,750
2009	8,360	8,347	8,360	8,322	8,365	8,360
2010	10,438	10,374	10,434	10,285	10,442	10,435
2011	13,556	13,255	13,610	12,817	13,356	13,490
2012	16,014	13,747	18,496	14,970	16,063	16,442
2013	18,595	14,260	21,671	16,409	17,862	19,446
2014	21,266	14,567	24,476	18,004	20,159	22,233
2015	23,432	15,093	26,316	19,211	22,358	24,136
2016	24,922	15,793	28,147	20,839	24,109	25,385
2017	26,266	16,970	30,089	22,476	25,807	26,612
2018	27,831	18,537	31,696	23,803	27,233	28,098
2019	29,209	19,787	33,074	25,128	28,564	29,415
2020	30,861	21,038	34,465	26,528	30,177	30,999
2021	32,271	22,393	36,030	28,240	31,371	32,407
2022	33,514	24,011	37,237	29,837	32,733	33,799
2023	34,342	25,512	38,295	31,241	33,665	34,824
2024	34,980	26,348	39,266	32,998	34,530	35,672
2025	35,715	26,749	39,820	34,230	35,548	35,948
2026	36,204	27,438	40,160	35,156	35,467	36,521
2027	36,371	28,318	40,669	35,742	35,683	37,106
2028	36,618	28,796	41,655	35,867	36,096	37,295
2029	36,774	28,787	42,665	35,751	36,669	37,531
2030	36,833	29,566	44,748	35,767	37,620	38,276

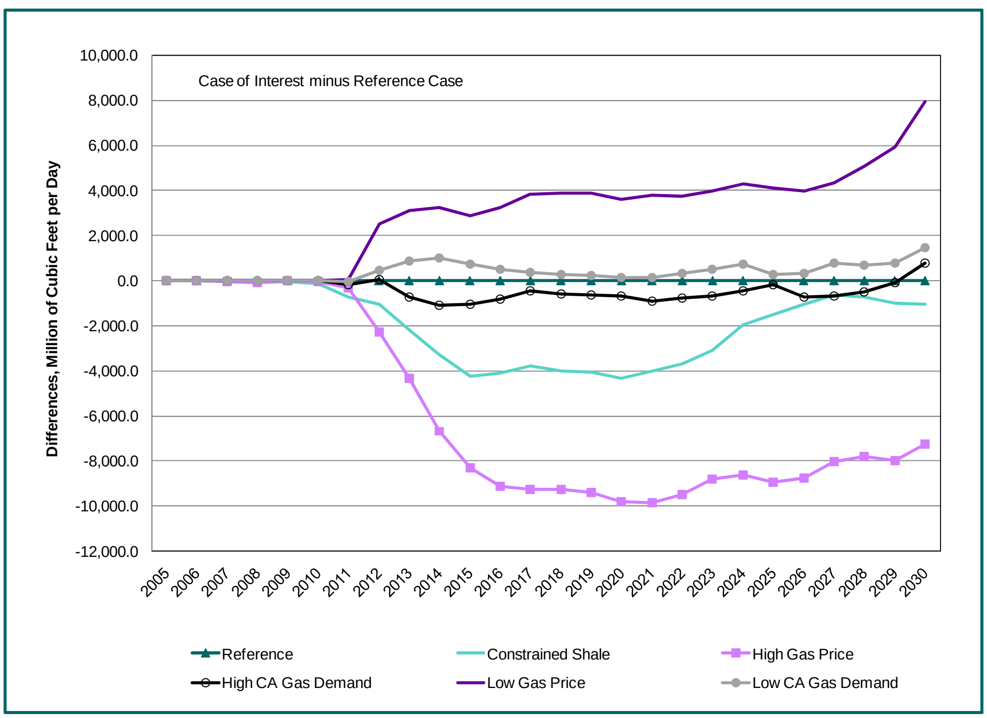
Source: California Energy Commission staff analysis.

Figure 8: Differences in United States Gas Production Across All Cases, MMcf/d



Source: California Energy Commission staff analysis.

Figure 9: Differences in United States Shale Gas Production Across All Cases, MMcf/d



Source: California Energy Commission staff analysis.

In a dynamic market such as the natural gas market, price changes can produce two responses:

- Consumers of natural gas purchase more gas if prices fall or less if prices rise.
- Suppliers of natural gas produce more gas for the marketplace if prices rise or less if prices fall.

All the cases result in some combination of these two responses, as the competing behaviors of economic agents represented in the model translate into a net effect that shows up as the sometimes unexpected, but nevertheless explainable, result.

High Gas Price Case

In the world of higher prices as assumed in the High Gas Price Case, the dominant effect appears to be less natural gas production from suppliers as a result of lower consumer demand. **Figure 8** and **Figure 9** show this is the case for both United States production from all sources and production from shale formations as a separate class. Starting in 2010, natural gas production falls below the Reference Case and remains lower than the Reference Case until 2030. Higher prices push United States production 11.1 percent lower in 2020 and 6.5 percent lower in 2030. Total Lower 48 shale production displayed a similar trend. However, in the localized market of California, higher prices stimulated higher natural gas production. California imports about 85 percent of its natural gas requirements and, as a result, a higher price environment stimulated local supply more than it suppressed demand. **Table 9** shows the percentage changes from the Reference Case.

Table 9: High Gas Price Case Gas Production Compared to Reference Case

	Percentage Change from Reference Case	
	2020	**2030**
United States Production	-11.1	-6.5
Shale Production	-31.8	-19.7
California Production	4.5	33.1

Source: California Energy Commission staff analysis.

Low Gas Price Case

In the world of lower prices as assumed in the Low Gas Price case, the dominant effect appears to be more natural gas production from suppliers as a result of higher consumer demand. **Figure 8** and **Figure 9** show this is the case for both United States production from all sources and production from shale formations as a separate class. Starting in 2010, natural gas production exceeds the Reference Case and remains higher through 2030. Lower prices stimulate natural gas demand that, in turn, causes production to edge higher. **Table 10** shows the percentage changes. United States production climbs 2.3 percent higher in 2020 and 8.7 percent higher in 2030. Total Lower 48 shale gas production and California displayed similar trends, although California's production, by 2030, exhibited the largest impact.

Table 10: Low Price Case Gas Production Compared to Reference Case

	Percentage Change from Reference Case	
	2020	**2030**
United States Production	2.3	8.7
Shale Production	11.7	21.5
California Production	6.0	30.6

Source: California Energy Commission staff analysis.

Constrained Shale Gas Case

In the world of higher prices that result from the higher costs assumed for shale gas production in this case, the dominant effect appears to be less natural gas production from suppliers as a result of lower consumer demand. However, the response to higher prices of natural gas in the High Gas Price Case exceeds that of the Constrained Shale Gas Case, as expected, since the former case resulted in moving gas market prices higher than the latter. Starting in 2010, natural case production falls below the Reference Case and remains lower until 2030. Higher prices dampen demand, pushing United States production lower by 5.9 percent in 2020 and by 3.2 percent in 2030. Total Lower 48 shale gas production displayed a similar trend. However, in the localized market of California, higher prices, at first, stimulate higher natural gas production. However, by 2030, demand suppression results in lower local production. **Table 11** displays the percentage changes from the Reference Case.

Table 11: Constrained Shale Case Gas Production Compared to Reference Case

	Percentage Change From Reference Case	
	2020	**2030**
United States Production	-5.9	-3.2
Shale Production	-14.0	-2.9
California Production	5.8	-5.2

Source: California Energy Commission staff analysis.

High and Low CA Demand Cases

The changes to Reference Case assumptions, which created the High and Low CA Gas Demand cases, lead to much smaller magnitude shifts in gas production as displayed in **Table 12**.

Table 12: Percentage Change From Reference Case
(Low CA Demand and High CA Demand)

	Low CA Demand		High CA Demand	
	2020	**2030**	**2020**	**2030**
United States Production	0.9	1.6	-1.3	<0.1
Shale Production	0.4	3.9	-2.2	2.1
California Production	1.1	-4.6	2.3	4.2

Source: California Energy Commission staff analysis.

The natural gas market stretches through North America, with pipelines linking regions in the three countries. The North American continent interacts with the rest of the world through "floating pipelines," tankers filled with LNG. Minor demand changes in one region, such as California in these cases, will not affect production in the major producing basins of North America or of the rest of the world. As a result, United States natural gas production from all sources, and from shale gas formations as a separate class, exhibited minor shifts when compared to the Reference Case.

Infrastructure-Related Modeling Results

This section discusses highlights of modeling results related to the volumes of natural gas flows between points of interest in the North American gas system, focusing on United States and California in most cases. Flows that cross international boundaries are referred to as exports or imports.[23] Pipeline flows are discussed as well as flows of LNG imported or exported by LNG tankers. When exports or imports are discussed, the volumes are the implied gross annual flows in one direction that result from the geographical balancing of supply and demand. Model results also report the usage levels of available pipeline capacity and pipeline capacity additions that the model's capacity expansion function calculates would be economic under the assumed current and future conditions.

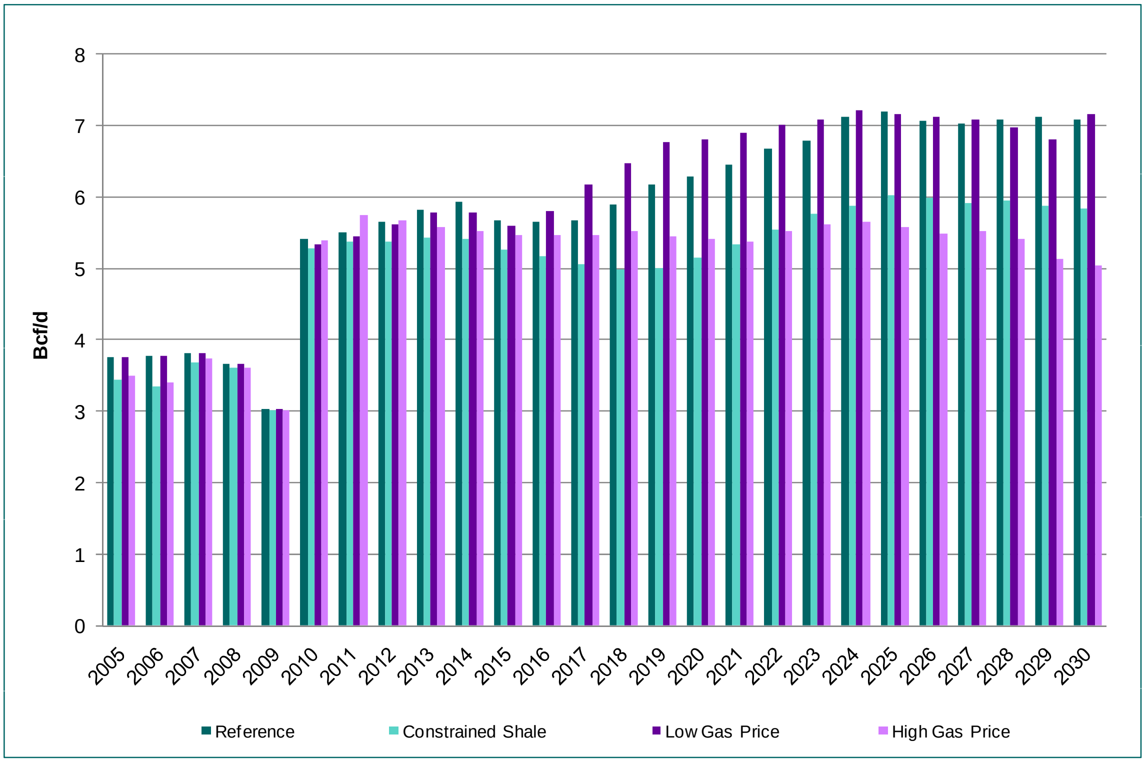
Depending on the scale, natural gas flows are generally reported in units of billions or millions of cubic feet per day. As mentioned, this is simply the annual volume divided by 365—an "annual daily averaging" of the model's annual inputs and outputs.

Pipeline Exports

Figure 10 shows the pipeline-transported exports from the United States for the Reference Case and the cases focused on moving gas prices. From 2010 to 2015, levels of pipeline exports across all cases remain relatively close. In the Low Gas Price Case, beginning in 2017, pipeline exports from the United States begin to ramp up higher than in any case. By 2024, export levels in the Reference Case become even with the Low Gas Price Case and remain that way through 2030. The natural gas that is produced in the United States becomes very competitive with markets in Mexico and Canada as prices remain relatively low. Conversely in the High Gas Price Case, the pipeline exports are pushed lower than in any other case because its high gas prices make it a less favorable option for markets in Canada and Mexico. In the Constrained Shale Gas Case, exports are likewise lower than in the Reference Case, but to a lesser extent because this case's assumed higher environmental mitigation costs of gas production affect prices less than the assumptions in the High Gas Price Case.

23 The modeler can also refer to flows into or out of any demand or supply node (or collection of them) of interest in the model as an import to or export from that node, respectively.

Figure 10: Pipeline Exports From the United States in Price-Focused Cases (Bcf/d)

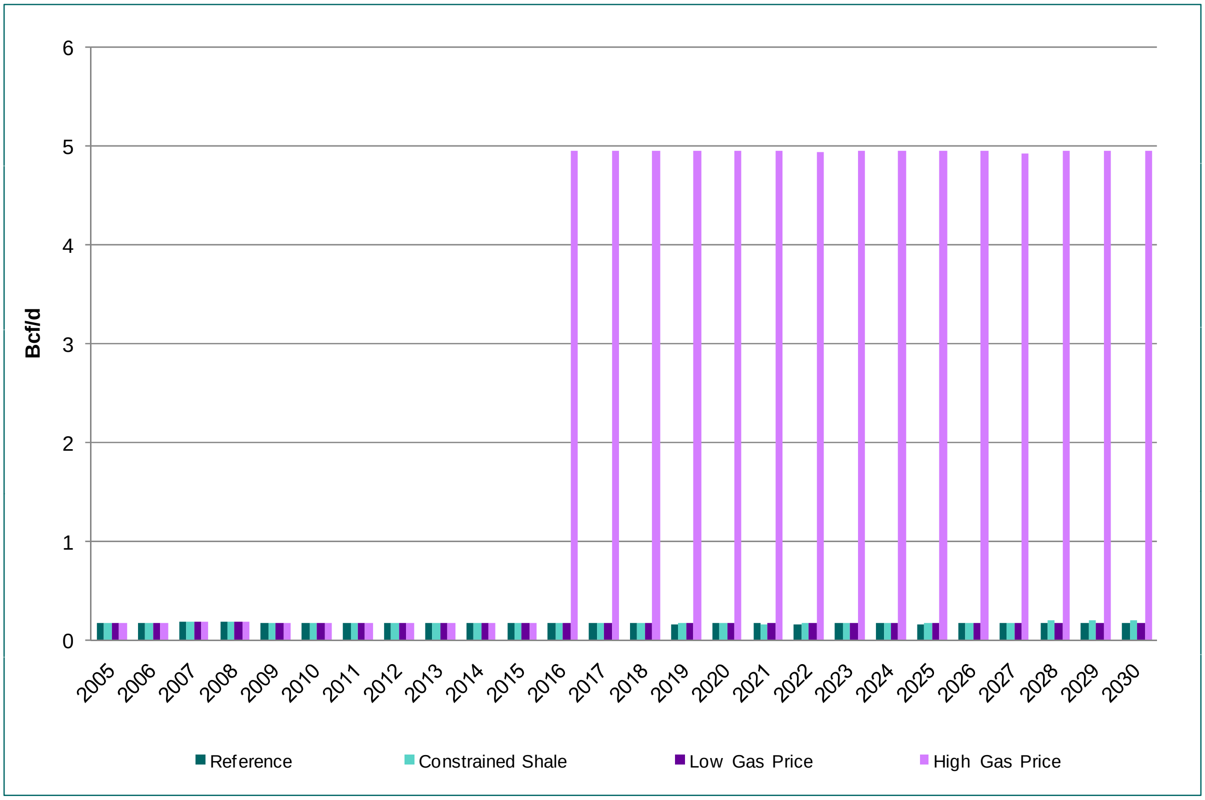


Source: California Energy Commission staff analysis.

Liquefied Natural Gas Exports From the United States

In the High Natural Gas Price Case, LNG exports were imposed as an input assumption through required contracts. The export amount for the High Gas Price Case in **Figure 11** illustrates the input assumption to have roughly 5 Bcf/d of contractual exports from the United States. The intention of having required exports was to help effect higher United States natural gas prices for the High Gas Price Case. All of the other cases in **Figure 11** did not have contractual obligations to export LNG and only did so when it became economically feasible. All the other cases for this comparison produced export levels that remained fairly constant at 0.5 Bcf/d through 2030. In none of the cases did the assumed future conditions lead to significant LNG exports being economically competitive.

Figure 11: Liquefied Natural Gas Exports From United States in Price-Focused Cases (Bcf/d)



Source: California Energy Commission staff analysis.

Liquefied Natural Gas Imports

How imports of LNG to the United States change across the modeled cases is of interest, given that the recent very competitive gas production from domestic shale formations may not have been anticipated by the developers of the LNG infrastructure.

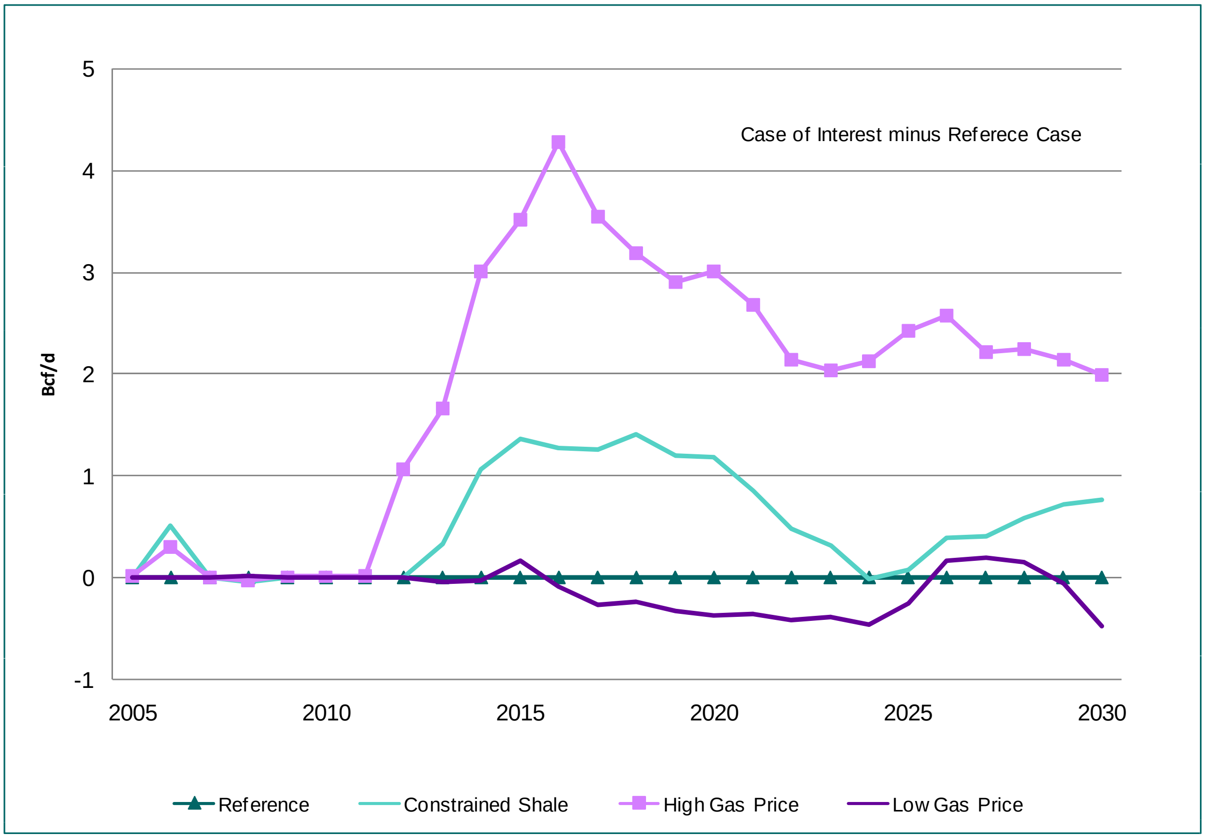
Table 13 shows the volume of LNG imports to the United States in the Reference Case and the changed cases designed to move national gas prices (the Constrained Shale Gas, High Gas Price, and Low Gas Price cases). **Figure 12** simply highlights the differences from the Reference Case among the cases shown in **Table 13**. The High Gas Price Case produces the highest levels of LNG imports when compared to the other cases. Under those prices (driven by higher GDP, more coal-fired power plant retirements and less renewable generation, constrained development at some shale formations, and higher environmental mitigation costs), foreign gas sources delivered as LNG become more cost-competitive with domestic supplies.

Table 13: Liquefied Natural Gas Imports to United States in Price-Focused Cases (Bcf/d)

Year	Reference	Constrained Shale	High Gas Price	Low Gas Price
2005	5.08	5.09	5.10	5.08
2006	3.35	3.86	3.65	3.35
2007	4.23	4.23	4.22	4.23
2008	2.35	2.31	2.31	2.36
2009	2.48	2.48	2.48	2.48
2010	2.98	2.98	2.98	2.98
2011	2.08	2.08	2.08	2.08
2012	2.94	2.94	4.00	2.94
2013	2.94	3.27	4.59	2.89
2014	3.14	4.20	6.15	3.10
2015	3.24	4.60	6.75	3.40
2016	3.13	4.40	7.40	3.04
2017	3.10	4.35	6.64	2.83
2018	2.94	4.34	6.12	2.69
2019	2.93	4.12	5.82	2.60
2020	2.92	4.10	5.92	2.54
2021	2.87	3.72	5.53	2.50
2022	2.94	3.42	5.07	2.52
2023	2.97	3.29	5.00	2.58
2024	3.03	3.02	5.15	2.57
2025	2.93	3.00	5.34	2.67
2026	2.93	3.32	5.50	3.08
2027	2.94	3.35	5.15	3.13
2028	2.91	3.49	5.15	3.05
2029	3.03	3.74	5.16	2.96
2030	3.22	3.98	5.20	2.74

Source: California Energy Commission staff analysis.

Figure 12: Difference in Liquefied Natural Gas Imports to United States Across Price-Focused Cases, (Bcf/d)



Source: California Energy Commission staff analysis.

Since the Constrained Shale Gas Case shared the same assumptions as the Reference Case except for the higher environmental mitigation costs for domestic gas production, its LNG imports are less than that of the High Gas Price Gas but still higher than in the Reference Case, as expected. The more severe future demand- and supply-side conditions assumed in the High Gas Price Case moved prices more than the assumed increase in mitigation costs of the Constrained Shale Gas Case, which pushed out significantly less LNG imports.

LNG import levels for the Low Gas Price Case are consistently lower than in the Reference Case. Driven by assumed lower GDP and increased renewable generation on the demand-side, and on the supply-side by assumed increases in gas resource availability and the rate of gas technology development, and with no additional environmental restrictions on production, the resulting lower prices for domestic supply outcompete LNG imports. With foreign markets paying much higher prices for LNG-delivered gas, under these assumed conditions, North America is an even less attractive market.

Imports From Canada to the United States

Shown in **Table 14** are United States imports of pipeline gas from Canada for the Reference Case and the cases focused on moving gas prices. The differences between these cases and the Reference Case are highlighted in **Figure 13**. Following the same pattern as seen with United States imports of other foreign gas supplies via LNG, and for the same reasons, the assumed future conditions in the High Gas Price Case lead to the highest level seen in any case of United States imports from Canada. With domestic supplies assumed to be constrained or available at higher cost than in the Reference Case, other sources such as Canadian imports and LNG are increased to make up the difference.

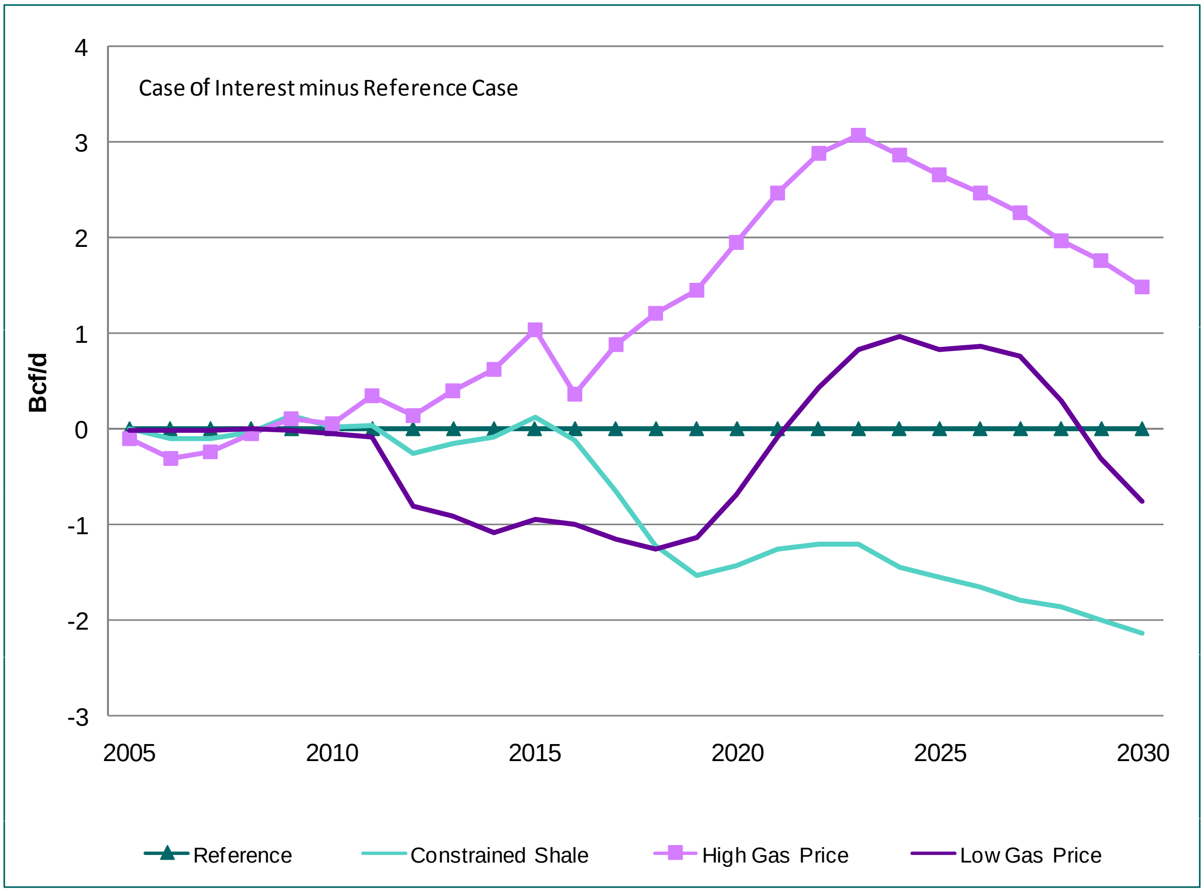
Natural gas import levels in the Low Gas Price Case start out relatively low and then steadily increase to be greater than the Reference Case in later years. While United States domestic natural gas prices are low in this case, the price for natural gas in Canada is low as well in the later years of the model and is able to better compete. However in the last years of the data reflected in **Figure 13**, Canadian import levels in the Reference Case surpass the import levels shown in the Low Gas Price Case.

Table 14: United States Imports From Canada in Price-Focused Cases (Bcf/d)

Year	Reference	Constrained Shale	High Gas Price	Low Gas Price
2005	10.53	10.53	10.44	10.53
2006	10.02	9.91	9.71	10.02
2007	9.71	9.60	9.48	9.71
2008	9.77	9.74	9.73	9.77
2009	8.10	8.24	8.21	8.09
2010	9.37	9.39	9.44	9.33
2011	8.23	8.27	8.58	8.16
2012	8.17	7.91	8.31	7.37
2013	7.88	7.72	8.29	6.98
2014	7.62	7.54	8.24	6.53
2015	7.28	7.40	8.33	6.35
2016	7.62	7.51	7.99	6.63
2017	8.14	7.47	9.02	7.00
2018	8.69	7.47	9.91	7.44
2019	9.18	7.65	10.64	8.05
2020	9.38	7.94	11.33	8.70
2021	9.45	8.20	11.92	9.38
2022	9.53	8.32	12.41	9.96
2023	9.68	8.47	12.75	10.52
2024	10.04	8.60	12.92	11.02
2025	10.52	8.97	13.18	11.36
2026	10.82	9.18	13.30	11.70
2027	11.21	9.41	13.48	11.99
2028	11.82	9.96	13.79	12.11
2029	12.37	10.37	14.14	12.07
2030	12.87	10.74	14.35	12.13

Source: California Energy Commission staff analysis.

Figure 13: Difference in United States Imports From Canada Across Price-Focused Cases, (Bcf/d)



Source: California Energy Commission staff analysis.

The Constrained Shale Gas Case produces the lowest overall levels of Canadian imports when compared with the other cases in **Figure 13**. For the Constrained Shale Gas Case, it is assumed that environmental restrictions are imposed in shale resource areas in Canada as well as in the United States. With natural gas production from shale in Canada made more expensive, the cost-competitiveness of exporting Canadian shale gas to the United States is reduced in the Constrained Shale Gas Case. The High Gas Price Case also has environmental restrictions on the Canadian shale plays as well. However, LNG exports are imposed in this case beginning in 2016, and increased levels of imports from Canada then become more competitive again.

Pipeline Capacity Additions

Pipeline and other gas transportation capacity expansions are determined within the WGTM by the endogenously calculated current and future prices, along with exogenous assumptions about capital costs of expansion, operating and maintenance costs of new and existing capacity, and revenues resulting from future outputs and prices.

Table 15 shows that the Low Gas Price Case makes the most additions to pipeline capacity when compared with the other cases. The Low Gas Price Case assumes that there are larger resource assessments in the Marcellus, Haynesville, and Western Canadian shales. With lower prices also stimulating demand, flows increase, spurring significant additions to the national pipeline capacity.

Table 15: Pipeline Capacity Additions in Price-Focused Cases

Cumulative Pipeline Capacity Additions (2010-2030)	Tcf
Reference Case	
Outside CA (Arizona, Oregon, Utah, Wyoming)	0.1889
CA	0.3942
Constrained Shale Gas Case	
Outside CA (Arizona, Oregon, Utah, Wyoming)	0.1606
CA	0.3351
High Gas Price Case	
Outside CA (Arizona, Oregon, Utah, Wyoming)	0.1166
CA	0.3315
Low Gas Price Case	
Outside CA (Arizona, Oregon, Utah, Wyoming)	0.2479
CA	0.4229

Source: California Energy Commission staff analysis.

Conversely, domestic natural gas supplies were made less cost-competitive with the additional environmental mitigation costs in the Constrained Shale Gas Case. As a result, less pipeline capacity was added when compared to the Reference Case. Finally, the lowest relative amounts of pipeline capacity additions were made in the High Gas Price Case. Requirements for additional pipeline capacity in this case were lessened by price-induced demand reductions and by having supply regions curtailed and bearing additional environmental costs.

As reflected in **Table 16**, the High California Gas Demand Case produced the highest additions to pipeline capacity when compared to the Reference Case and the Low California

Gas Demand Case. Most of the capacity additions for this case occurred with interstate pipelines that delivered supplies of natural gas to the California border. The take-away capacity (California intrastate pipelines) additions nearly kept pace with the out-of-state additions. Conversely, the Low Gas Demand Case saw fewer pipeline capacity additions when compared to the Reference Case. For this case, however, take-away capacity additions were greater than the capacity additions that bring natural gas to the borders of California.

Table 16: Pipeline Capacity Additions in Demand-Focused Cases

Cumulative Pipeline Capacity Additions (2010-2030)	Tcf
Reference Case	
Outside CA (Arizona, Oregon, Utah, Wyoming)	0.1889
CA	0.3942
CA High Gas Demand Case	
Outside CA (Arizona, Oregon, Utah, Wyoming)	0.6931
CA	0.6482
CA Low Gas Demand Case	
Outside CA (Arizona, Oregon, Utah, Wyoming)	0.1460
CA	0.2773

Source: California Energy Commission staff analysis.

The ability to add capacity was turned off within the Lowered Pressure Case for 2012 to 2016. However, the ability to add capacity in this case was turned on after 2016, and the cumulative sum of capacity additions to 2030 is reflected in **Table 17**. The model did make adjustments and compensated for its inability to add capacity between the 2012 and 2016. However, most of the additional pipeline compensation occurred with interstate pipelines that serve California. The additions to interstate pipeline capacity in the Lowered Pressure Case are highlighted when compared to the Reference Case.

Table 17: Pipeline Capacity Additions in Lowered Pressure Case

Cumulative Pipeline Capacity Additions (2010-2030)	Tcf
Reference Case	
Outside CA (Arizona, Oregon, Utah, Wyoming)	0.1889
CA	0.3942
Lowered Pressure Case	
Outside CA (Arizona, Oregon, Utah, Wyoming)	0.2254
CA	0.3790

Source: California Energy Commission staff analysis.

Pipeline Capacity Utilization Rates

Staff calculates a figure of merit called the *pipeline utilization rate* to indicate how heavily that transportation asset is being used. Each pipeline segment in the model has a known (assumed) maximum annual volume that can flow through it in a year (its annual capacity). As part of its solution, the WGTM calculates the annual volume of gas traveling through each pipeline segment represented in the model. The pipeline utilization rate is the fraction of the model's resulting annual flow compared to its maximum annual flow.

Pipeline utilization rates of WGTM model results followed corresponding trends exhibited for pipeline capacity additions. Selected pipeline utilization rates in the Reference Case and cases focused on moving prices are shown in **Table 18**. Overall, the Low Gas Price Case showed the highest pipeline utilization rates when compared with the other cases. Because California final equilibrium gas demand in the model is higher in this case, and supply is more readily available, most of the pipelines are used at a relatively higher rate.[24] For this case, the low utilization rates on the Ruby Pipeline were compensated by increased use on the TransCanada Gas Transmission Northwest (GTN) pipeline.

The Constrained Shale Gas Case and the High Gas Price Case proved to have some of the lowest pipeline utilization rates when compared with the other cases. With higher prices and less domestic natural gas being produced in the Constrained Shale Gas Case, efficient use of the pipeline system decreased. Efficient use of the pipelines is further lessened when the price-induced demand decrease in the High Gas Price Case is factored in.

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24 Some of the input assumption changes made to create the Low Gas Price Case, with the intention of moving national prices lower, reduced the reference quantity gas demand, which are input assumptions to the WGTM, but more so for out-of-state gas demand than for in-state. Facing the lower prices, in-state demand ended up being slightly higher in the changed case than in the Reference Case. Nationally, the opposite occurred.

Table 18: Pipeline Utilization Rates in Price-Focused Cases, 2030 and 2022

Pipeline Utilization Rate (%)	EPNG+TW+MJ (2030)	GTN (2030)	KRGT (2030)	Ruby (2030)
Reference Case	35.80	92.30	66.30	28.30
Constrained Shale Gas Case	35.50	80.90	64.40	33.60
High Gas Price Case	34.90	80.50	61.00	33.30
Low Gas Price Case	37.10	95.10	70.70	30.40
Pipeline Utilization Rate (%)	**EPNG+TW+MJ (2022)**	**GTN (2022)**	**KRGT (2022)**	**Ruby (2022)**
Reference Case	36.82	68.46	72.87	47.72
Constrained Shale Gas Case	36.09	59.58	66.77	45.89
High Gas Price Case	34.52	62.07	67.84	48.40
Low Gas Price Case	35.11	81.55	70.70	39.04

Source: California Energy Commission staff analysis.

Note: EPNG+TW+MJ refers to El Paso Natural Gas, Transwestern and Mojave aggregate pipeline corridor

Note: GTN and KRGT refer to the TransCanada Gas Transmission Northwest and Kern River pipeline respectively

Table 19 shows selected pipeline utilization rates in the Reference Case and cases focused on moving gas demand in California. Utilization rates along the El Paso Natural Gas (EPNG) aggregate pipeline corridor remained fairly constant through time and across all cases. However, when utilization rates on the GTN pipeline increased, there was a noticeable decrease in usage of both the Kern River and Ruby pipelines across all cases. Overall, the High CA Gas Demand Case made the most use of the available pipeline capacity that delivers natural gas to the borders of California. The Low CA Gas Demand produced lower pipeline utilization rates when compared to the Reference Case for 2030 and 2022.

Table 19: Pipeline Utilization Rates in Demand-Focused Cases, 2030 and 2022

Pipeline Utilization Rate (%)	EPNG+TW+MJ (2030)	GTN (2030)	KRGT (2030)	Ruby (2030)
Reference Case	35.80	92.30	66.30	28.30
CA High Gas Demand Case	40.14	97.56	70.94	48.63
CA Low Gas Demand Case	39.57	88.99	62.11	28.77
Pipeline Utilization Rate (%)	**EPNG+TW+MJ (2022)**	**GTN (2022)**	**KRGT (2022)**	**Ruby (2022)**
Reference Case	36.82	68.46	72.87	47.72
CA High Gas Demand Case	43.74	70.87	74.90	35.39
CA Low Gas Demand Case	40.22	71.24	69.88	43.84

Source: California Energy Commission staff analysis

Note: EPNG+TW+MJ refers to El Paso Natural Gas, Transwestern and Mojave aggregate pipeline corridor

Note: GTN and KRGT refer to the TransCanada Gas Transmission Northwest and Kern River pipeline respectively

Pipeline Flows and the Lowered Pressure Case

When comparing the Lowered Pressure Case to the Reference Case, the result that becomes quickly apparent is the redistribution of pipeline flow. The total amount of natural gas being delivered to California between the two cases remains fairly constant for all the years of comparison in **Table 20**. The key difference is the change in flows along the Redwood and Baja Paths. For the Low Pressure Case, maximum capacity on the Redwood and Baja Paths were reduced by 200 MMcf/d and 300 MMcf/d, respectively. When compared to the Reference Case, there is increased flow on the Baja Path and decreased flow for the Redwood Path in the Low Pressure Case. There is also noticeably less flow on the GTN pipeline between the two cases for 2012 to 2016. Staff emphasizes that the ability to add more pipeline capacity in California for 2012 to 2016 was turned off for the Low Pressure Case. Because the Baja Pipeline was operating at lower maximum capacity while handling increased flow of natural gas, a larger utilization rate was produced for this pipeline for 2012 to 2016 in the Lowered Pressure Case. Flow on the Redwood Path was slightly reduced while still producing higher utilization rate due to the reduced maximum capacity level used in the Low Pressure Case. Flows on all other major pipelines that serve California remained fairly even when comparing the two cases for 2012 to 2016. **Table 21** shows the corresponding utilization rate comparison between the Reference Case and the Lowered Pressure Case.

Table 20: Lowered Pressure Case Pipeline Flows (Tcf/year) for Model Years 2012 to 2016

Pipeline Flows Tcf/yr	EPNG+TW+MJ (2012)	GTN (2012)	KRGT (2012)	Ruby (2012)	Baja (2012)	Redwood (2012)
Reference Case	0.89	0.58	0.55	0.00	0.28	0.50
Low Pressure Case	0.88	0.58	0.54	0.00	0.26	0.50
	EPNG+TW+MJ (2013)	**GTN (2013)**	**KRGT (2013)**	**Ruby (2013)**	**Baja (2013)**	**Redwood (2013)**
Reference Case	0.78	0.48	0.46	0.26	0.14	0.60
Low Pressure Case	0.80	0.44	0.46	0.27	0.15	0.58
	EPNG+TW+MJ (2014)	**GTN (2014)**	**KRGT (2014)**	**Ruby (2014)**	**Baja (2014)**	**Redwood (2014)**
Reference Case	0.76	0.52	0.45	0.25	0.11	0.63
Low Pressure Case	0.78	0.47	0.46	0.25	0.14	0.58
	EPNG+TW+MJ (2015)	**GTN (2015)**	**KRGT (2015)**	**Ruby (2015)**	**Baja (2015)**	**Redwood (2015)**
Reference Case	0.75	0.53	0.45	0.25	0.11	0.63
Low Pressure Case	0.79	0.48	0.47	0.24	0.15	0.68
	EPNG+TW+MJ (2016)	**GTN (2016)**	**KRGT (2016)**	**Ruby (2016)**	**Baja (2016)**	**Redwood (2016)**
Reference Case	0.75	0.55	0.46	0.24	0.11	0.62
Low Pressure Case	0.78	0.49	0.48	0.23	0.16	0.58

Source: California Energy Commission staff analysis.

Note: EPNG+TW+MJ refers to El Paso Natural Gas, Transwestern and Mojave aggregate pipeline corridor.

Note: GTN and KRGT refer to the TransCanada Gas Transmission Northwest and Kern River pipeline respectively.

Table 21: Lowered Pressure Case Pipeline Utilization Rate for Model Years 2012 to 2016

Pipeline Utilization Rate (%)	EPNG+TW+MJ (2012)	GTN (2012)	KRGT (2012)	Ruby (2012)	Baja (2012)	Redwood (2012)
Reference Case	43.30	60.39	83.38	0.00	66.09	63.44
Low Pressure Case	43.23	60.61	82.16	0.00	85.62	69.80
Pipeline Utilization Rate (%)	**EPNG+TW+MJ (2013)**	**GTN (2013)**	**KRGT (2013)**	**Ruby (2013)**	**Baja (2013)**	**Redwood (2013)**
Reference Case	38.29	50.25	69.66	58.45	33.41	75.92
Low Pressure Case	38.92	46.16	69.82	61.42	50.00	81.46
Pipeline Utilization Rate (%)	**EPNG+TW+MJ (2014)**	**GTN (2014)**	**KRGT (2014)**	**Ruby (2014)**	**Baja (2014)**	**Redwood (2014)**
Reference Case	36.92	54.12	69.21	56.39	26.92	79.87
Low Pressure Case	38.33	48.89	70.43	56.16	46.41	81.18
Pipeline Utilization Rate (%)	**EPNG+TW+MJ (2015)**	**GTN (2015)**	**KRGT (2015)**	**Ruby (2015)**	**Baja (2015)**	**Redwood (2015)**
Reference Case	36.67	55.38	68.90	55.94	26.20	80.51
Low Pressure Case	38.39	50.00	71.49	53.88	48.69	95.08
Pipeline Utilization Rate (%)	**EPNG+TW+MJ (2016)**	**GTN (2016)**	**KRGT (2016)**	**Ruby (2016)**	**Baja (2016)**	**Redwood (2016)**
Reference Case	36.43	57.36	69.51	53.65	26.20	78.60
Low Pressure Case	38.33	51.19	73.17	51.37	50.98	81.88

Source: California Energy Commission staff analysis.

Note: EPNG+TW+MJ refers to El Paso Natural Gas, Transwestern and Mojave aggregate pipeline corridor.

Note: GTN and KRGT refer to the TransCanada Gas Transmission Northwest and Kern River pipeline respectively.

Given the WGTM's annual averaging approach, the Lowered Pressure Case should not be viewed as a test for natural gas delivery reliability given reduced capacity levels on the Redwood and Baja pipeline. The Low Pressure Case provides some insight as to how pipeline capacity use is redistributed due the reduced pressure on the Redwood and Baja pipelines. This information could prove useful in the long-term planning of possible pipeline capacity expansions. Daily gas balancing and the ability to inject and release natural gas from storage can play an important role in ensuring the daily reliable delivery of natural gas but are not modeled in the WGTM.

Demand-Related Results

This section highlights United States and California results from the WGTM related to natural gas demand. It first briefly touches on residential, commercial, and industrial demand to later spend more time on results about the electric generation sector gas demand. Activities in the power sector are key drivers of natural gas demand. Most of the cases in this study were designed specifically to examine the potential effects on the gas market of activities in the power sector, especially as they may be affected in the future by policies or regulations related to public health and safety and the environment. Demand results for all sectors are included in the Excel worksheets described in Appendix C and posted on the *2011 IEPR* website.

The section closes with a discussion of a simple post-processing analysis staff conducted to provide some additional demand-related metrics of both general and policy interest. Staff examines the differences across the cases in estimates of the total cost of gas combusted by the power sector and the amount of carbon dioxide (CO_2) emissions emitted from that combustion. These are not meant to be definitive absolute cost or emissions estimates for each case; rather they are an attempt to translate output metrics about gas volumes into additional policy-relevant metrics, which are directly related to broader public interests.

Residential and Commercial Sectors

United States GDP is identical to national income; therefore, as public income changes, spending on commodities, such as natural gas, changes. The assumption about future growth in United States GDP is one of the most significant factors influencing residential and commercial gas demand. The Reference Case assumption for average annual growth of GDP is 2.6 percent. Two of the cases designed to move gas market prices varied this assumption, while all other cases assumed the Reference Case value. The High Gas Price Case assumed a 3.5 percent annual average GDP growth rate, and the Low Gas Price Case assumed 2.1 percent growth. Although these GDP assumptions were selected to move demand,[25] that was essentially a means to move price. Within the WGTM, the resulting price then acts on price-elastic demand, pushing the final equilibrium-state demand back in the opposite direction. Changes to other input assumptions that were intended to affect price directly also have this interrelationship with demand. These counteracting forces make the magnitude of the outcome, if not the direction, difficult to predict.

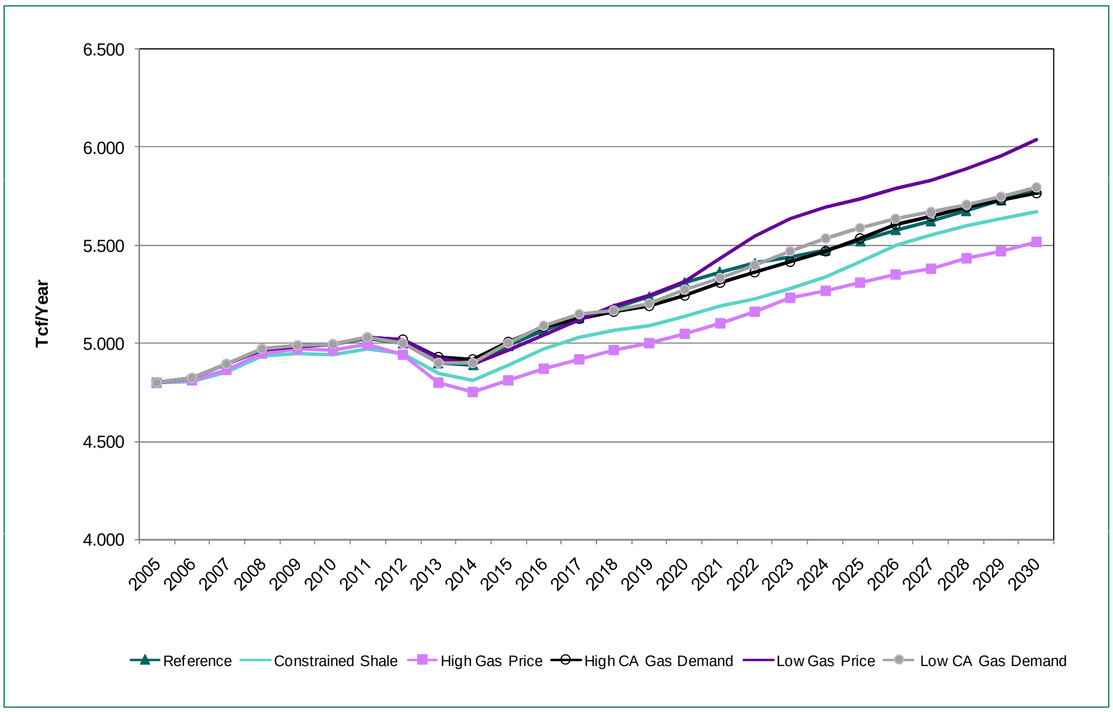
The WGTM model's gas demand response in the United States and California residential and commercial sectors is shown in **Figure 14**, **Figure 15**, **Figure 16**, and **Figure 17**. With the exception of the United States commercial demand, the differences between their highest- and lowest-demand cases reach their maxima at the 2030 forecast horizon, and the trends beyond 2014 are all relatively linear. The differences in demand between the cases with the highest and the lowest demand in each figure result in a range from 5.3 percent in the United States commercial sector (**Figure 16**) to 10.9 percent in the California commercial sector (**Figure 17**). The High CA Gas Demand Case is responsible for the California commercial sector having the widest range of differences. Although it has the same 2.6 percent GDP growth rate as the Reference Case, the High CA Gas Demand Case specified other assumptions that were designed to drive California gas demand up. Of these assumptions, the three most influential were:

25 Here, demand refers to the reference quantity of demand that is input to the WGTM, but which is the output of the econometric model that uses a GDP assumption as one of its inputs.

- Removing all electric generation from California's two nuclear plants by 2026.
- Slowing the rate of added new renewable electric generation.
- Increasing California's total electric generation growth rate.

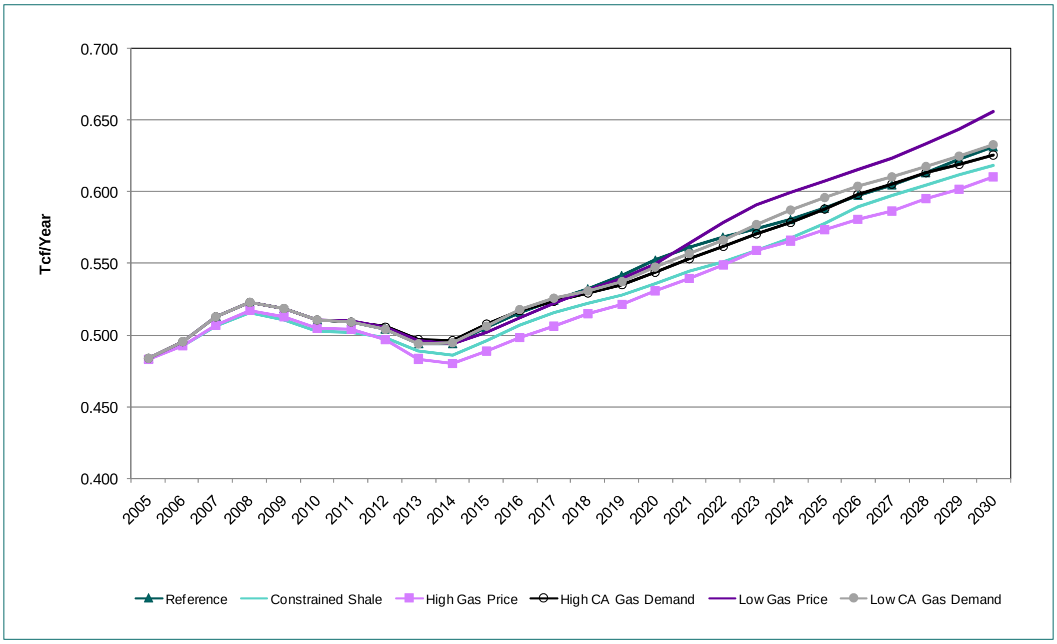
The other five cases, in contrast, trend closely together with the Reference Case, as do all of the United States commercial sector results shown in **Figure 16**.

Figure 14: United States Residential Gas Demand: Reference Case and Change Cases (Tcf/year)



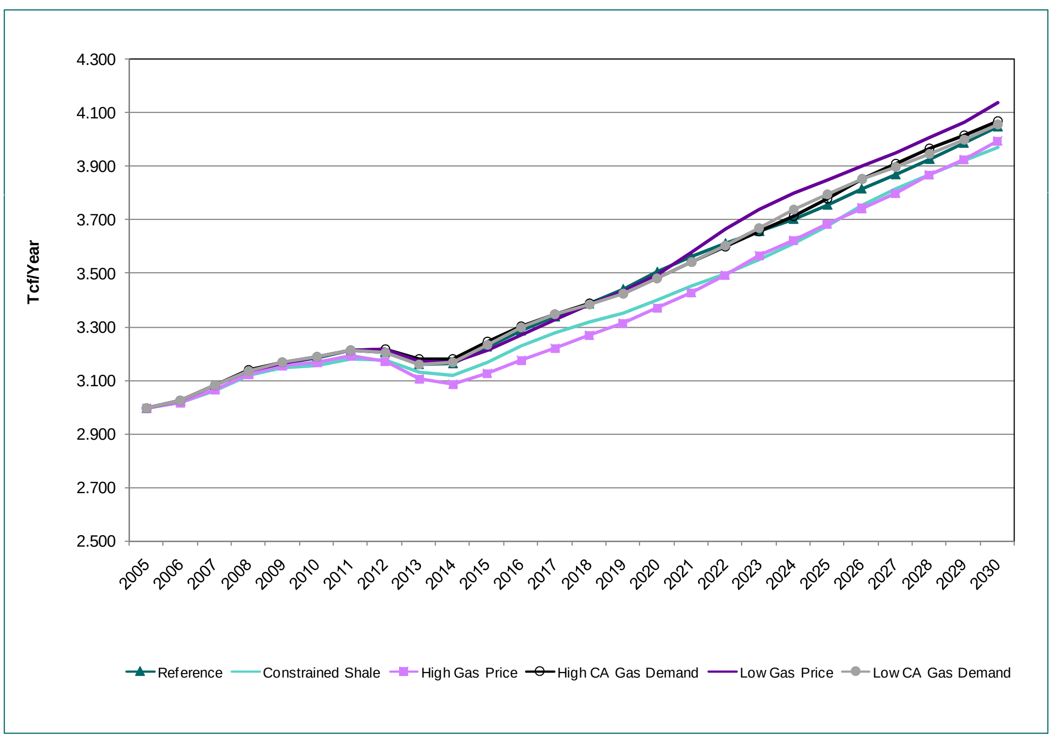
Source: California Energy Commission staff analysis.

Figure 15: California Residential Gas Demand: Reference Case and Change Cases (Tcf/year)



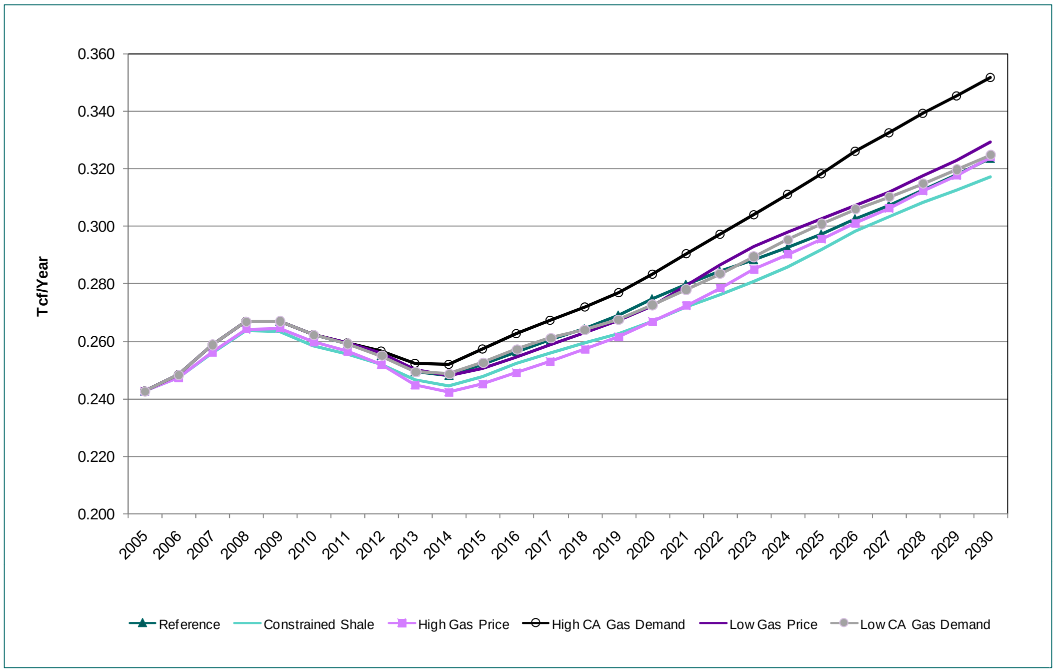
Source: California Energy Commission staff analysis.

Figure 16: United States Commercial Gas Demand—Reference Case and Change Cases (Tcf/year)



Source: California Energy Commission staff analysis.

Figure 17: California Commercial Gas Demand: Reference Case and Change Cases (Tcf/year)

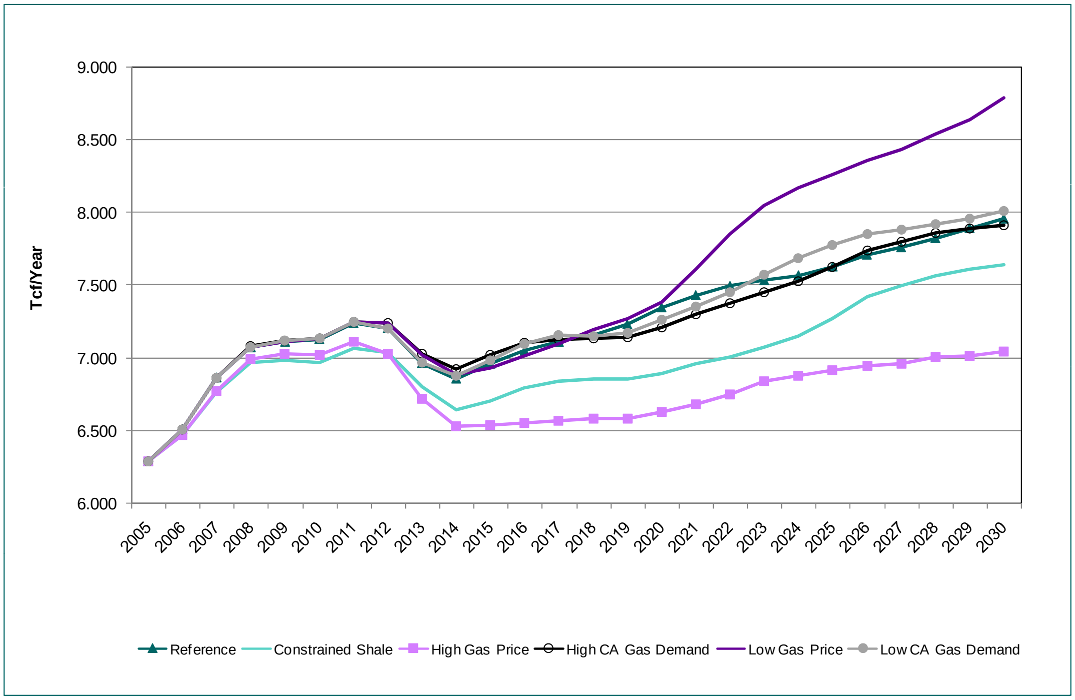


Source: California Energy Commission staff analysis.

Industrial Sector Results

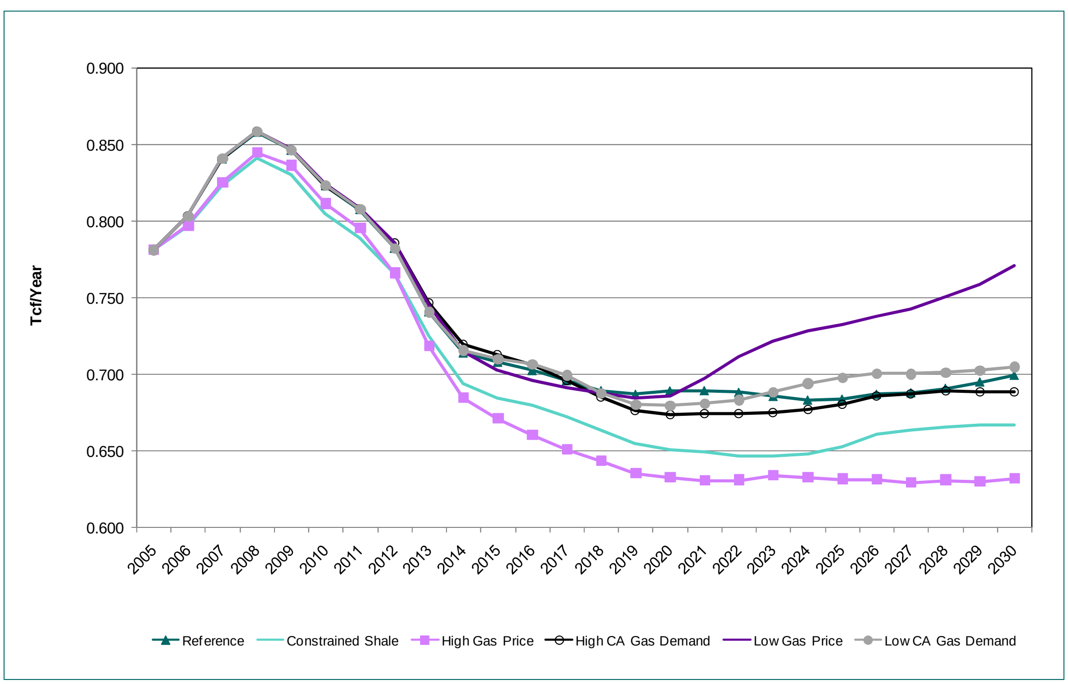
In contrast to the residential and commercial sector results, the United States and California industrial sector highest and lowest case results for 2030 differ by 25 and 22 percent, respectively. Another contrast with the other two sectors is the divergence of three of the cases—the Low Gas Price, Constrained Shale, and High Gas Price—from the Reference, High CA Demand, and Low CA Demand cases, as shown in **Figure 18** and **Figure 19**.

Figure 18: United States Industrial Gas Demand: Reference Case and Change Cases (Tcf/year)



Source: California Energy Commission staff analysis.

Figure 19: California Industrial and Enhanced Oil Recovery Gas Demand: Reference Case and Change Cases (Tcf/year)



Source: California Energy Commission staff analysis.

The cases designed to move gas market prices—the Low Gas Price, Constrained Shale, and High Gas Price cases—altered global and national gas supply and electric generation assumptions from the Reference Case and, therefore, had the biggest impact on industrial gas demand. The cases designed to move demand for gas in California—the Low and High CA Gas Demand cases—only changed assumptions in this state and none of the global or national gas supply or demand assumptions. The wide divergence in industrial sector demand responses suggests that this sector, which historically has demonstrated a response to gas prices that is more than twice the residential or commercial sector price elasticities, uses switching to cheaper fuels, energy efficiency measures, conservation, or changes to production methods. Two other responses to alter long-run gas demand often available to the industrial sector that are not usually available to the residential and commercial sectors include moving production overseas and increasing capitalization of more energy-efficient industries at the expense of energy-intensive industries. United States growth in high-value information technologies with the concomitant decline of steel, automobiles, and other heavy manufacturing is an example of this response.

A final interesting observation is the contrast between California and the United States industrial gas demand. California industrial sector changed case results show an almost identical pattern of spread around the Reference Case, with the highest gas demand result in the Low Gas Price Case and the lowest gas demand in the High Gas Price Case. The United States industrial gas demand increases after 2014 for all cases, including the High Gas Price Case, which by 2030 increases the North American gas benchmark Henry Hub prices 11.3 percent. The case assumptions achieve this result in part by increasing GDP annual average growth to 3.5 percent, removing 280,000 GWh, or 5.3 percent, of United States coal-fired generation, delaying other states' implementation of an RPS by 15 years, constraining LNG imports from major overseas sources, and assuming robust LNG exports. United States industrial demand is highest in the Low Gas Price Case and lowest in the High Gas Price case. The significant contrast is that while all cases show United States industrial gas demand recovering after 2014, all cases in **Figure 19** show California industrial gas demand declining through 2020 and most cases leveling off, with only the Low Gas Price case showing significant growth after 2020.

Power Generation Sector

The principal objectives of California policy makers for the power generation sector are intended to advance the public interest in clean, reliable, efficient, and inexpensive electricity. Environmental and energy efficiency policy initiatives often target the power generation sector and consequently have substantial effects on that sector's gas demand. Two important reasons for why policy makers mark this sector for these policy initiatives is the lower cost of implementation and compliance compared to the other three sectors. Power plants, in contrast to homes and commercial and many industrial businesses, are large facilities whose numbers in any area are small. Therefore, policy makers can more easily identify these facilities and their operators and efficiently collaborate with them on developing regulations that improve energy efficiency or emissions objectives. The second reason policy makers maintain this interest is that the thermal power plant fleet of fossil-fueled generators contributes a significant share of total United States emissions: 2,100 million metric tons of CO_2, 5.7 million tons of sulphur dioxide (SO_2), and 4.7 million tons of oxides of nitrogen (NO_x).[26]

Since many of the assumptions about key drivers that varied across the changed cases are focused on the power generation sector, they are not repeated here. It will be helpful for the reader to review the Chapter 2 descriptions of changed assumptions in each case as well as that chapter's display of results of the econometric modeling that produces the electric generation gas demand input assumptions to the WGTM.[27] In addition, the reader is reminded of the snapshot sheets provided at the beginning of Chapter 3, which provide a summary of key driver input changes across cases and some selected output values for each case.

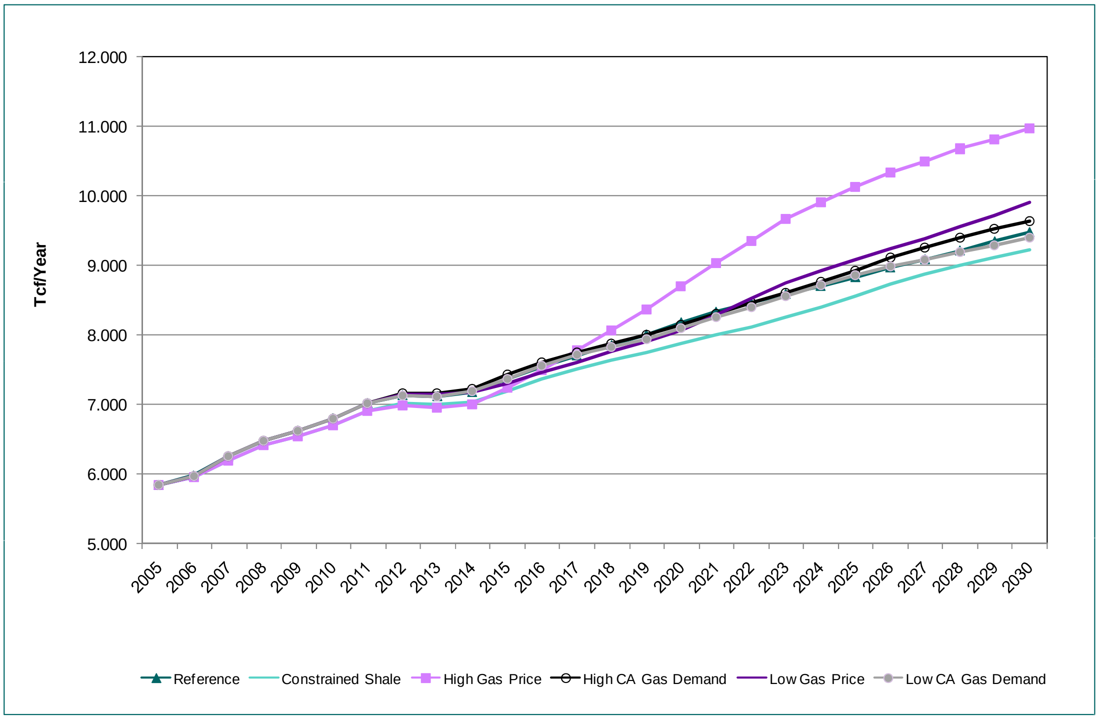
Power Sector Natural Gas Demand

The WGTM power sector gas demand results for the United States and for California are shown in **Figure 20** and **Figure 21** for the Reference Case, for the three cases designed to move gas market prices, and for the two cases designed to move California gas demand. Not surprisingly, United States power generation gas demand is highest in the High Gas Price Case, which had the most severe input assumption changes affecting the United States electric generation mix (**Figure 20**). This case assumed all states with an RPS program suffered an additional 5-year delay in reaching their RPS targets (10 years total, when added to the five-year delay assumed in the Reference Case). In addition, 50,000 MW of coal-fired generating capacity (and 280,000 GWh of electricity generation) were assumed to retire.

26 Moniz, Ernest J., and others. Massachusetts Institute of Technology. 2011. *The Future of Natural Gas: An Interdisciplinary MIT Study*, Table 4.2, p. 85. The term "NO_x" refers to the two oxides of nitrogen—nitrogen oxide (NO) and nitrogen dioxide (NO_2)—included in fossil-fueled power plant emissions.

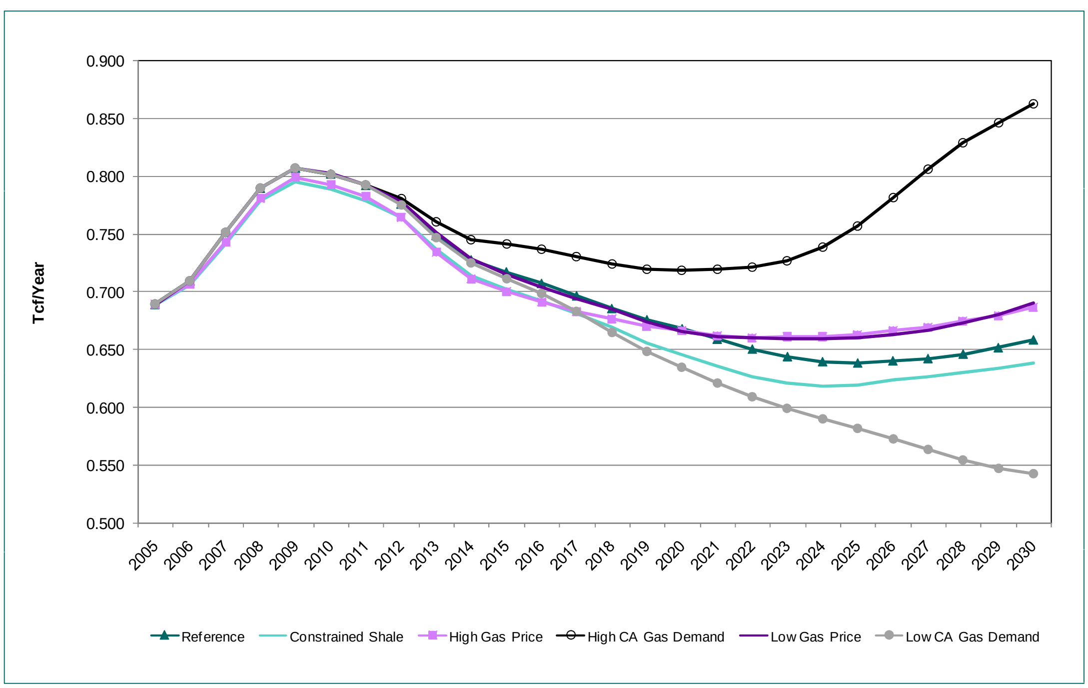
27 This refers to the reference quantities of gas demand for electric generation, which are inputs to the WGTM. The final equilibrium quantities of electric generation gas demand, which output of the WGTM, are presented and discussed in this chapter. Staff makes no direct comparison in this report between the reference quantities and final equilibrium quantities, which would show the effects of price elasticities of demand for gas in that sector.

Figure 20: United States Power Generation Gas Demand, All Cases, Tcf/year



Source: California Energy Commission staff analysis.

Figure 21: California Power Generation Gas Demand, All Cases, Tcf/year



Source: California Energy Commission staff analysis.

California power generation gas demand is highest in the High CA Gas Demand Case, in which more than 34,000 GWh of in-state nuclear generation is assumed to shut down after 2025; the RPS does not reach 33 percent until 2029; total electric generation growth is slightly higher than in the Reference Case; and some additional electric vehicle charging is assumed (**Figure 21**). California power generation gas demand is lowest in the Low CA Gas Demand Case, in which total electric generation growth is slightly lower than in the Reference Case, 6,000 MW (and 8,500 GWh) of non-RPS-eligible renewable generation is added, and the RPS continues to increase above 33 percent of retail sales by 1 percent per year until leveling off at 40 percent by 2027 and beyond.

Power Sector Cost and Emission Vulnerabilities

Along with the potential range of electric generation gas demand seen across the cases comes a range of potential vulnerability to the costs and environmental consequences of that gas consumption. Although the same could be done for gas consumption in all end-use sectors, staff roughly estimates three new (that is, exogenous to the WGTM) policy-relevant figures of merit to give power generation gas demand a dimension other than just cubic feet of gas. Calculated from the WGTM output for power sector gas demand, the three estimated metrics are:

- Total cost of natural gas consumed in power generation, in billions of $2010.
- CO_2 emissions from the combustion of the generating fuel, in metric tons (tonnes).
- Cost of CO_2 allowances required under Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006) (AB 32) cap-and-trade program for the combusted fuel, in $2010.

The focus is on the differences among cases rather than the absolute values, since these are estimates and only the power sector is included in this post-processing analysis. Staff assumed a weighted-average end-use gas price to generators to apply to statewide gas demand by generators from the WGTM (**Table 22**). Staff estimates only the emissions from combustion of gas, which are tracked in the WGTM. (Fugitive methane emissions are not.) Staff assumes a CO_2 emission factor for natural gas of 119 lbs CO_2/MMBtu.[28] Staff's assumption for CO_2 cost in **Table 23** is conservatively low, at about the level of AB 32 cap and trade program "reserve" allowance price established for gas utilities, about $17/tonne (nominal $, in 2020).

28 (119 lbs CO_2/1 MMBtu)*(0.053977 tonnes/119 lbs)*(1025 Btu/cf)*(1000000 MMcf/Tcf) = tonnes CO_2/year.

Table 22: Volume-Weighted Average of California Gas Utilities' End-Use Price to Electric Generators, $2010/MMBtu

Case	2017	2022	2030
Reference	$5.99	$6.45	$6.83
High Gas Price	$6.41	$6.75	$7.52
Low Gas Price	$6.02	$5.80	$5.92
Constrained Shale Gas	$6.29	$6.82	$7.20
High CA Demand	$6.15	$6.51	$6.94
Low CA Demand	$6.14	$6.31	$6.78
Lowered Pressure	$6.19	$6.43	$6.80

Source: California Energy Commission staff analysis.

Table 23: Carbon Allowance Cost Assumption Using "Reserve" Price

Year	Nominal $/Tonne	$2010/Tonne
2012	$10.00	$9.74
2013	$10.66	$10.10
2014	$11.36	$10.53
2015	$12.11	$11.01
2016	$12.90	$11.51
2017	$13.75	$12.07
2018	$14.65	$12.66
2019	$15.62	$13.30
2020	$16.64	$13.98
2021	$17.74	$14.68
2022	$18.90	$15.42
2023	$20.15	$16.19
2024	$21.47	$17.00
2025	$22.88	$17.85
2026	$24.39	$18.74
2027	$25.99	$19.67
2028	$27.70	$20.65
2029	$29.52	$21.68
2030	$31.46	22.76

Source: California Energy Commission staff analysis.

Table 24 presents California power generation gas demand and the above-mentioned metrics for the Reference Case, the three cases designed to move the gas prices, and the two cases designed to move California gas demand for the snapshot years of 2017, 2022.

Focusing on the differences across cases, to get an appreciation for the range the future cost or emission vulnerability might be, staff shows how the value in each case varies from the Reference Case level for each metric. **Figure 22** shows the differences across cases in California power generation gas demand, in Tcf/yr, from the Reference Case. **Figure 23** shows the total cost of gas combusted in California power generation by case. As seen in **Table 22**, since the price of gas is an output of the WGTM and different in each case, the weighted average cost of gas to electric generators also varies by case. Therefore, the relationship between the amount of gas burned and cost of gas burned is not linear.

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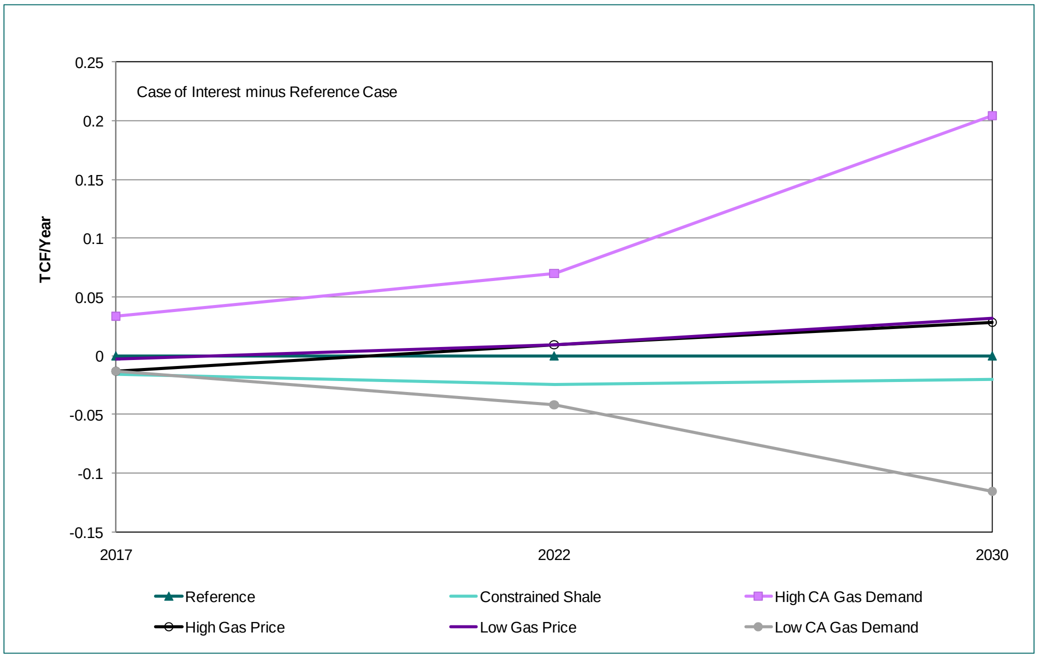
Table 24: Estimates of California Power Generation Sector Gas Demand, Gas Costs, Combustion CO_2 Emissions, and Minimum CO_2 Allowance Costs by Cases

Selected California Power Generation Sector Results	Reference	High Gas Price	Low Gas Price	Constrained Shale Gas	High CA Gas Demand	Low CA Gas Demand
2017						
Gas Demand (Bcf/Yr)	696.6	683.3	694.3	681.3	730.7	683.5
Combustion CO_2e Emissions (Millions Tonnes CO_2/yr)	38.5	37.8	38.4	37.7	40.4	37.8
Gas Costs (Millions $2010/yr)	$4,285.5	$4,498.0	$4,292.4	$4,401.4	$4,562.7	$4,197.7
CO_2e Allowance Costs (Millions $2010/yr)	$465.2	$456.3	$463.6	$455.0	$488.0	$456.4
2022						
Gas Demand (Bcf/yr)	650.7	660.2	660.2	626.8	720.9	609.3
Combustion CO_2e Emissions (Millions Tonnes CO_2/yr)	36.0	36.5.0	36.5	34.7	39.92	33.7
Gas Costs (Millions $2010/yr)	$4,310.1	$4,576.6	$3,932.4	$4,390.0	$4,679.2	$4,080.0
CO_2e Allowance Costs (Millions $2010/yr)	$555.1	$563.2	$563.2	$534.7	$615.0	$519.8
2030						
Gas Demand (Bcf/yr)	658.6	686.7	690.8	639.1	862.9	543.1
Combustion CO_2e Emissions (Millions Tonnes CO_2/yr)	36.4	38.0	38.2	35.4	47.7	30.0
Gas Costs (Millions $2010/yr)	$4,619.7	$5,303.7	$4,199.8	$4,726.1	$5,848.9	$3,753.8
CO_2e Allowance Costs (Millions $2010/yr)	$829.3	$864.8	$869.8	$804.8	$1,086.6	$683.9

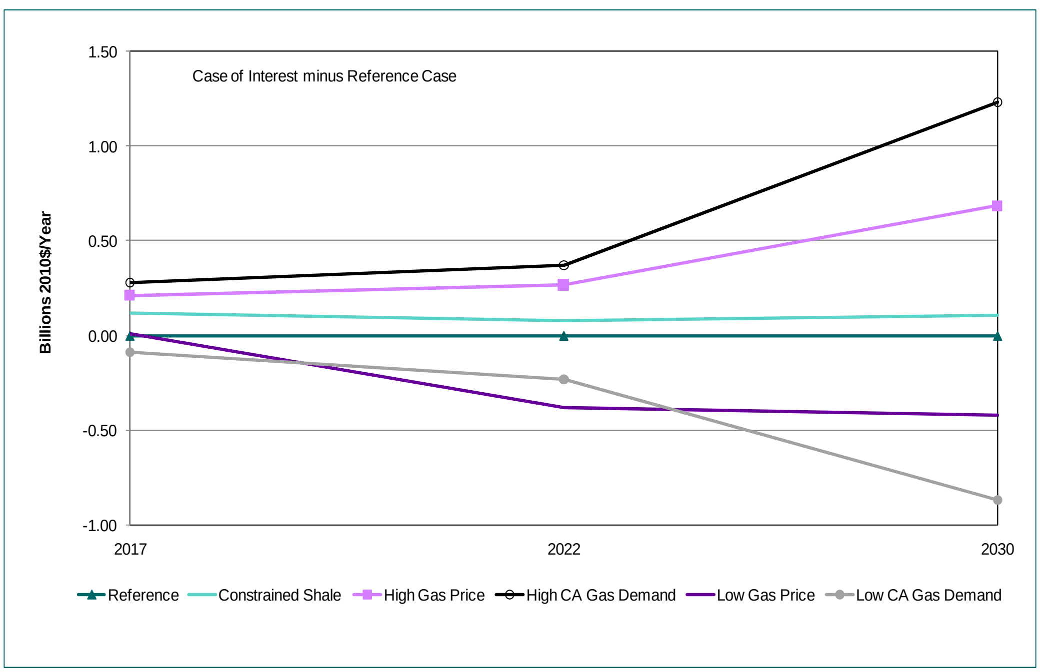
Source: California Energy Commission staff analysis.

Figure 22: Differences in California Power Generation Annual Gas Demand Across All Cases



Source: California Energy Commission staff analysis.

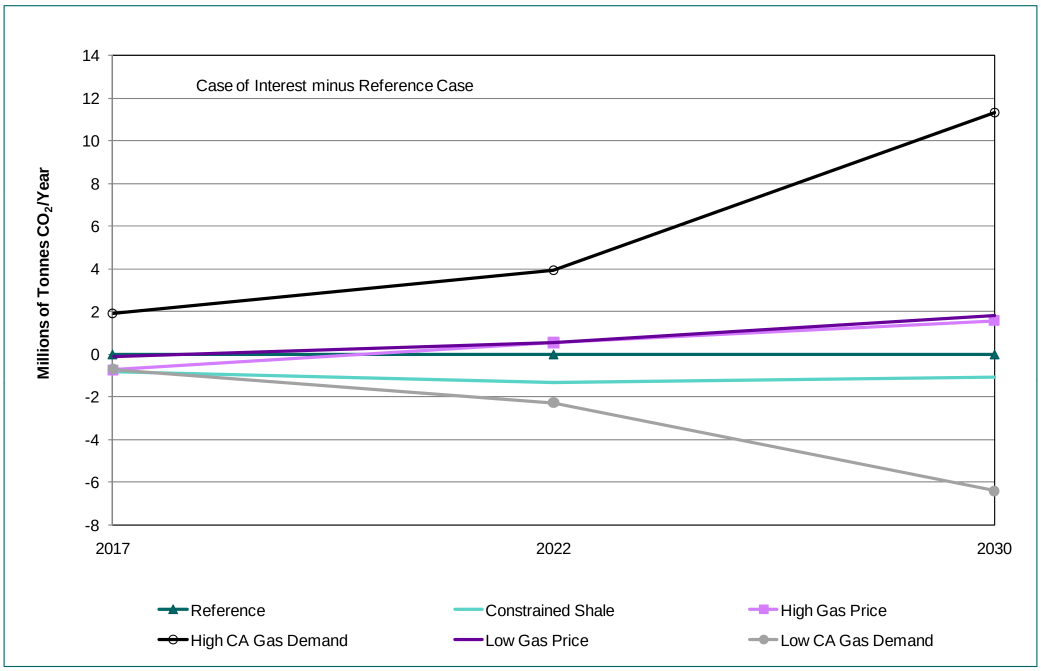
Figure 23: Differences in Estimated California Power Generation Annual Gas Costs Across All Cases



Source: California Energy Commission staff analysis.

Figure 24 shows the annual CO_2 emissions from electric generation across the cases in tonnes/year. This is a linear relationship with the gas demand because staff simply applied a 119 lbs CO_2/MMBtu emission factor. (The shapes of the lines in **Figure 22** and **Figure 24** are essentially the same.) To avoid making apples-to-oranges comparisons, this quantity of emissions is simply that emitted by gas-fired power plants in California as the state-by-state approach of the WGTM maps them. This is not the same as assigning "emissions responsibility" to Californians based on the emissions associated with the power they consume, regardless of the power plant location.

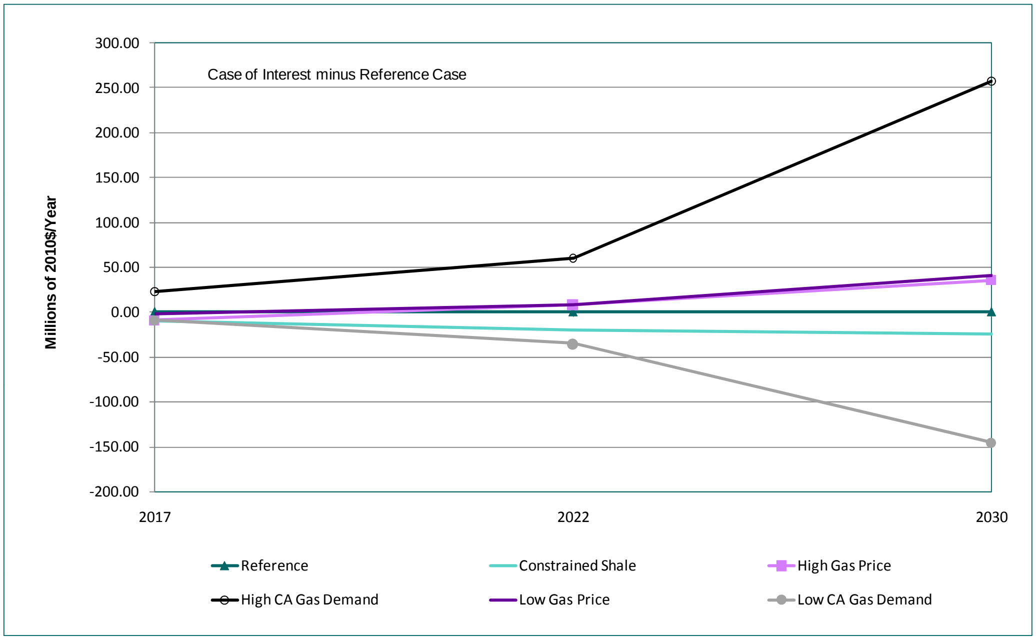
Figure 24: Differences in Estimated California Power Generation Annual CO_2 Emissions From Combustion Across All Cases



Source: California Energy Commission staff analysis.

Figure 25 shows the additional cost incurred if all of the CO_2 emissions from the natural gas combusted by power generation in California were obligated to have CO_2 allowances, paying the minimum reserve price described in the AB 32 cap-and-trade rulemaking. The minimum reserve price applies to the obligations of gas utilities, beginning in 2015, to have allowances to cover the emissions from the combustion of gas they deliver to their end-use customers smaller than the large industrial and power plant customers who come under the program in 2012. Large industrial facility and power plant owners will likely pay different GHG allowance prices than assumed here. Staff chose the minimum reserve price to represent a lower bound. Readers wanting to estimate additional allowance costs assuming higher emission costs can easily do so as this relationship is also linear.[29]

Figure 25: Differences in Estimated California Power Generation Annual Emission Allowance Costs Across All Cases



Source: California Energy Commission staff analysis.

Staff included the AB 32 GHG allowance cost as a post-processed "adder" to the WGTM price result, not as an input to the WGTM's balancing of gas supplies and demand.

Looking at the spread of these post-processed metrics across cases in 2022, staff observes that:

- Low Gas Price Case power generation annual gas costs are $380 million less, while High Gas Price Case generation annual gas costs are $270 million more than the Reference Case.
- Low CA Gas Demand Case annual CO_2 emissions are 2.3 million tonnes less, while High CA Gas Demand Case annual CO_2 emissions are 3.9 million tonnes more than in the Reference Case.
- Low CA Gas Demand Case annual CO_2 emission allowance costs are $35 million less, while High CA Gas Demand Case annual CO_2 emission allowance costs are $60 million more than in the Reference Case.

29 What allowance prices actually will be is not linear, just the estimate of the total allowance cost at any assumed allowance price.

By 2030, these spreads in cost of gas and tonnes of emissions more than double.

Another caveat to understand is that these estimates represent just part of a much larger, complex whole. While showing the incremental cost of gas or emissions from gas-fired generation, these figures are not indicative of a comprehensive tradeoff analysis. For example, the High Gas Price Case does have more gas-fired generation in California and so more gas costs, GHG emissions, and allowance costs than other cases. This case also has 280,000 GWh less coal-fired generation and the associated GHG emissions, as well as extensive capital costs to replace the coal capacity.

Reflecting on the Modeling Results

As expected, the modeling results directly reflect the assumptions staff made in each case about the future states of key drivers of natural gas market activities. Plausible alternative assumptions about future underlying conditions can significantly move national gas prices away from the level in the Reference Case.[30]

- The additional operating costs staff assumed for groundwater protection and environmental mitigation for gas extraction activities increased Henry Hub spot market prices in the Constrained Shale Gas Case about 4 percent above the Reference Case prices.[31]
- To these additional environmental mitigation costs, the High Gas Price Case further constrained the development of gas from some shale formations, increased annual GDP growth from 2.6 to 3.5 percent, delayed RPS implementation across the nation by 10 years, and removed 50,000 MW of coal-fired generation, which collectively increased Henry Hub spot market prices by about 10 percent above the Reference Case prices.
- In the other direction, the Low Gas Price Case assumptions of lowered annual growth in GDP (2.1 instead of 2.6 percent); higher United States and Canadian shale gas resource assessments; relaxed market entry constraints for Iran, Iraq, and Venezuela; and accelerated national RPS compliance collectively lowered Henry Hub spot market prices by about 6 percent below the Reference Case prices.

30 Staff has not attempted to "bookmark" the widest plausible range of input assumptions or model outcomes by specifying the highest and lowest plausible cases. To do that would require further elicitation of the judgment of experts in the various fields of activity affecting the underlying conditions. Even with this extra effort, experts may still be unable to agree on direction, magnitude, or likelihood of future specific conditions.

31 The average of the annual percentage differences between Constrained Shale Gas Case and Reference Case Henry Hub prices over the period 2012 to 2030 is 3.75 percent. The percentage differences between a changed case and the Reference Case shown in this section are all computed similarly.

Plausible alternative assumptions about future underlying conditions can also significantly move California gas demand away from the level in the Reference Case.

- The loss of SONGS and Diablo Canyon nuclear generation, a delay in RPS implementation, additional electric vehicle charging and natural gas vehicles, and a slight increase in annual average growth in electrical demand (perhaps from reduced energy efficiency savings) increased 2030 California gas demand in the High CA Gas Demand Case by about 31 percent above the Reference Case demand.
- In the other direction, an increase in California RPS compliance to 40 percent by 2027, an additional 8,500 GWh of renewable distributed generation by 2030, and a slightly slower annual average growth in electrical demand (perhaps from increased energy efficiency savings) decreased California gas demand in the Low CA Gas Demand Cases by about 18 percent below the Reference Case demand.

Having identified key drivers of natural gas market outcomes of widespread interest, such as prices, it is prudent to continue to monitor activities that affect these indicators. Doing so could conceivably reduce some uncertainty about their potential future states. Future economic conditions; the state of knowledge about the extent and economics of natural gas resources; progress of environmental, public safety, or energy policies directly or indirectly affecting coal-fired, nuclear, and renewable generation resources; regulations affecting access to natural gas resources; innovations in the technology of natural gas exploration, drilling, and production; international gas market developments; nuclear power plant relicensing and safety proceedings; and electric and natural gas vehicle transportation initiatives are all activities that staff will continue to monitor when assessing the natural gas market and making conditional estimates of future market outcomes.

The future states of the identified key drivers of gas prices are both beyond California's control and difficult to predict accurately. There are risks inherent in using any conditional estimate of future gas prices for planning or policy decisions. Ideally, these risks should be understood and managed in the decision-making process. Understanding the risks begins with understanding the effects on gas prices of uncertainties about the future states of their underlying drivers. Having a plausible range of estimates that clearly relate the input variables (future underlying conditions) to the results (market outcomes) is important to building this understanding. Decision-making processes that use a gas price estimate typically include estimates of other key factors, about which there is also uncertainty. The uncertainties in these estimates also contribute to the risks inherent in the decision-making. Ideally, the risk management assessment of the potential consequences of the decision would estimate a range of consequences of acting on the presumption that one estimate (of gas prices and all other factors that are uncertain and are key drivers of the consequences) will happen when it turns out that a different value than the presumed estimate actually occurs. With some understanding of the risks inherent in using the conditional estimates for a particular decision, the decision maker can judge how tolerable the risks seem, or modify the decision or policy to include mechanisms that work to directly reduce the risks.

CHAPTER 4: End-Use Gas Prices

Much of the nation's natural gas is delivered directly to large-volume end users, such as power plants and industrial facilities, by interstate or intrastate transmission pipeline companies. Residential and commercial consumers have their gas delivered by their local distribution company's network of lower pressure and smaller diameter distribution pipelines and laterals. The transmission pipeline companies deliver gas to the local distribution companies at their various citygate locations, where ownership of the gas transfers and the local distribution function is deemed to begin. Because of these differences in the way gas is delivered to end users in different sectors, the cost of delivery differs across sectors, and so, too, do the prices required to recover those costs. The more expensive-to-serve sectors pay higher prices, reflecting their higher costs of delivery. Residential customers pay the most for gas delivery, followed by commercial, industrial, and electric generation customers, respectively.

As described in Chapter 2, the WGTM estimates the commodity prices and interstate and intrastate transportation rates of delivering natural gas to the California border or to local distribution company citygate locations. The additional costs incurred by the distribution company to deliver the gas to its end users are estimated exogenously to the WGTM. For power plant and large industrial gas consumers served directly by interstate or intrastate transmission pipeline companies, staff begins with the WGTM's border price (rather than the citygate price) and adds exogenously estimated delivery costs.

Staff describes the various components of delivery costs by sector in this chapter as well as explains the method of estimating end-use delivery costs. Just as there is uncertainty about the future states for the key drivers of commodity prices and interstate transportation costs, there is uncertainty about the future states for the key drivers of delivery costs. The last section discusses some of the contributors to these uncertainties and provides some estimates of what effects they could have on future natural gas end-use prices.

This chapter focuses on methods, issues, and uncertainties related to future end-use pricing but does not provide price estimates for all of the gas distribution companies or all of the modeled cases. To illustrate the general discussion, staff uses only PG&E-related examples. However, staff did estimate each distribution company's end-user gas prices under all modeled cases. These estimates are available in Microsoft Excel worksheets on the *IEPR* website at: http://www.energy.ca.gov/2011_energypolicy/documents/2011-09-27 workshop/xls_results/.

In this chapter staff uses the terms *end-use price* and *end-use rates* somewhat interchangeably. Where the discussion refers to CPUC or other regulatory proceedings that establish specific transportation rates, then the term "rates" is used. Where the discussion refers to the combined total of all costs, including the gas commodity cost as well as transmission and distribution costs, then the term "price" is used.

Utility Cost to Operate the Distribution System

Table 25 illustrates the cost allocation associated with operating and maintaining a local distribution utility's distribution system. This table uses data from 2001 and is for SoCalGas. These numbers should be taken as an illustrative example of what goes into utility distribution costs and rates. These percentages may differ across utilities and be different in 2011.

Table 25: Local Distribution Utility System Cost Categories

Function	Percentage
Storage	5
Transmission	4
Distribution	14
Customer Accounts	10
Service and Information	5
Administration	26
Taxes	17
Depreciation	19
Total	100

Source: *2001 SoCalGas Annual Report to the CPUC*, pgs 317-325.

Utility transportation costs, often called "the margin" or utility "fixed costs," refer to all the costs associated with operating and maintaining the utility distribution system. They do not include the cost to purchase and deliver the natural gas to California.

The margin includes expenditures associated with operation, maintenance, administration, taxes, and depreciation. O&M costs are incurred for storage, transmission, and distribution. These costs are applied to cover engineering, record keeping, compressor and pipeline maintenance, compressor fuel, and controlling the flow of natural gas from supply sources to the end user.

Such things as meter reading, maintaining customer records, and collection expenses are included in Customer Accounts. Service and Information charges cover the expenses for customer assistance. Administration covers general salaries, office expenses, outside services and consulting, employee pensions, injuries, and so forth. The utilities are subject to local, state, and federal taxes. Finally, depreciation covers the aging of the utility system.

Method for Estimating End-Use Gas Prices

Staff estimated end-use natural gas prices for PG&E, SoCalGas, and SDG&E. For each utility, local transmission and distribution costs were added to the citygate price to obtain the end-use price. End-use prices are estimated for the residential, commercial, industrial, and power generation sectors. The data used to estimate the transmission and distribution costs comes from the CPUC's Biennial Cost Allocation Proceeding (BCAP) decision for each utility.

PG&E End-Use Prices

Staff used the partial settlement in the *2009 BCAP's Appendix 1* to calculate end-use natural gas prices for PG&E.[32] For residential transportation rates, the non-California Alternate Rates for Energy program (CARE) residential rate was used.[33] For commercial transportation rates, a volume-weighted average of small and large commercial customers was calculated. Industrial end-use transportation rates were calculated using a volume-weighted average of backbone-, transmission-, and distribution-level industrial customer service. For electric generation, the backbone-level transportation service rate was used.

SoCalGas End-Use Prices

The *2009 BCAP*[34] was used to calculate end-use natural gas prices for SoCalGas. For residential customers, the residential transportation rate was used. For the commercial customer transportation rate, the core commercial and industrial rate was used. The industrial end-use transportation rate is computed as the volume-weighted average of transmission- and distribution-level service for noncore commercial and industrial consumers. The electric generation end-use transportation rate is calculated as the volume-weighted average of transmission- and distribution-level electric generation customers. Staff's calculations are different for SoCalGas than for PG&E as the BCAP for each utility has a different level of detail.

SDG&E End-Use Prices

Information from the SoCalGas *2009 BCAP* was used to calculate end-use natural gas prices for SDG&E. The end-use transportation rates for SDG&E were computed using data from

32 See Table K and Table L at https://www.pge.com/regulation/BCAP-PGE-2009/CPUC/Draft-Decisions/2010/BCAP-PGE-2009_CPUC_Draft-Dec_20100623-01Atch01.pdf for the BCAP Appendix 1.

33 CARE rates apply to low-income customers.

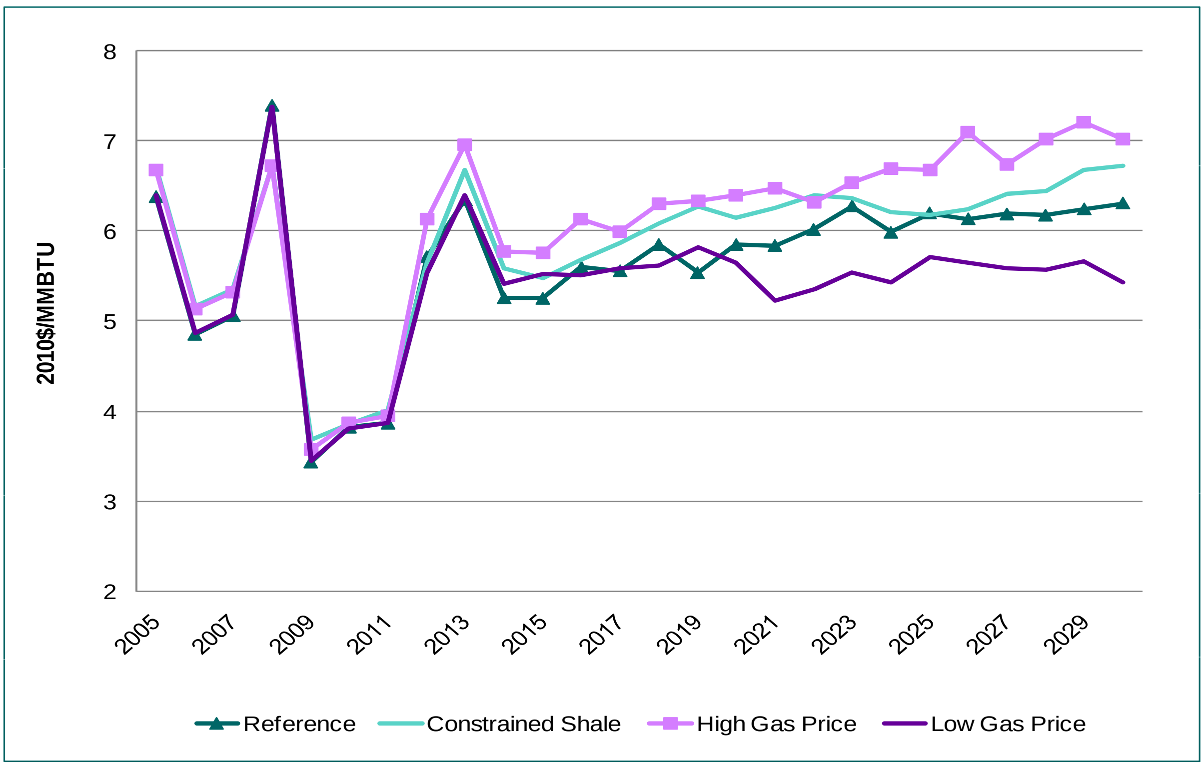
34 See Table 1 at http://www.socalgas.com/regulatory/documents/a-08-02-001/application_2008_0204.pdf for SoCalGas' BCAP.

rate tables in the 2009 SoCalGas BCAP.[35] These rates were calculated using the same method as for SoCalGas as the rate tables for both these utilities have the same amount of detail.

The following examples illustrate just PG&E. Other California utilities may have somewhat different natural gas commodity and transportation costs. These examples are intended to show the magnitudes of different transportation cost components and how different model scenarios affect end-use prices of natural gas.

Figure 26 plots the PG&E Citygate price for the Reference Case and the changed cases designed to move national gas market prices. This price plot should not be taken as the absolute high and low limits on natural gas prices, but rather a plausible range of what annual average equilibrium prices of natural gas could be given staff's assumptions for each case. From 2021 through 2030, the High Price Case is, on average, 10 percent higher than the Reference Case price, and the Low Price Case is, on average, 10 percent lower than the Reference Case price.

Figure 26: PG&E Citygate Prices Across Price-Focused Cases

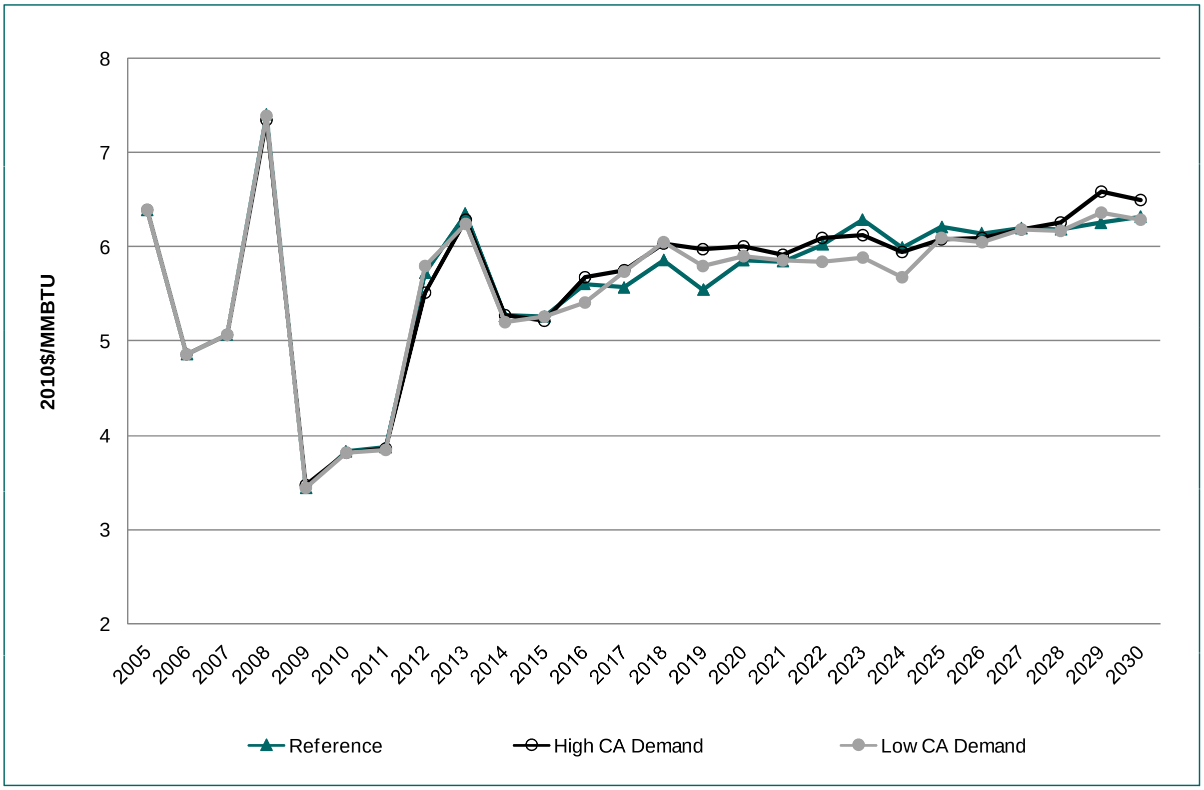


Source: Energy Commission staff analysis.

35 See http://www.socalgas.com/regulatory/documents/a-08-02-001/LRMC-NCORateTables.pdf page 6, Table 1.

Figure 27 shows how natural gas prices at PG&E Citygate are affected by the higher and lower levels of California gas demand in the modeled cases designed to move demand in California. The changes in California natural gas demand have a negligible effect on prices at the citygate. The price of natural gas at the Henry Hub shows the same story. California is a relatively small piece of the United States natural gas market and thus does not have a lot of market power to affect prices. The natural gas prices for SoCalGas Citygate and SDG&E Citygate are similar across these cases.

Figure 27: PG&E Citygate Price Across California Demand-Focused Cases



Source: Energy Commission staff analysis.

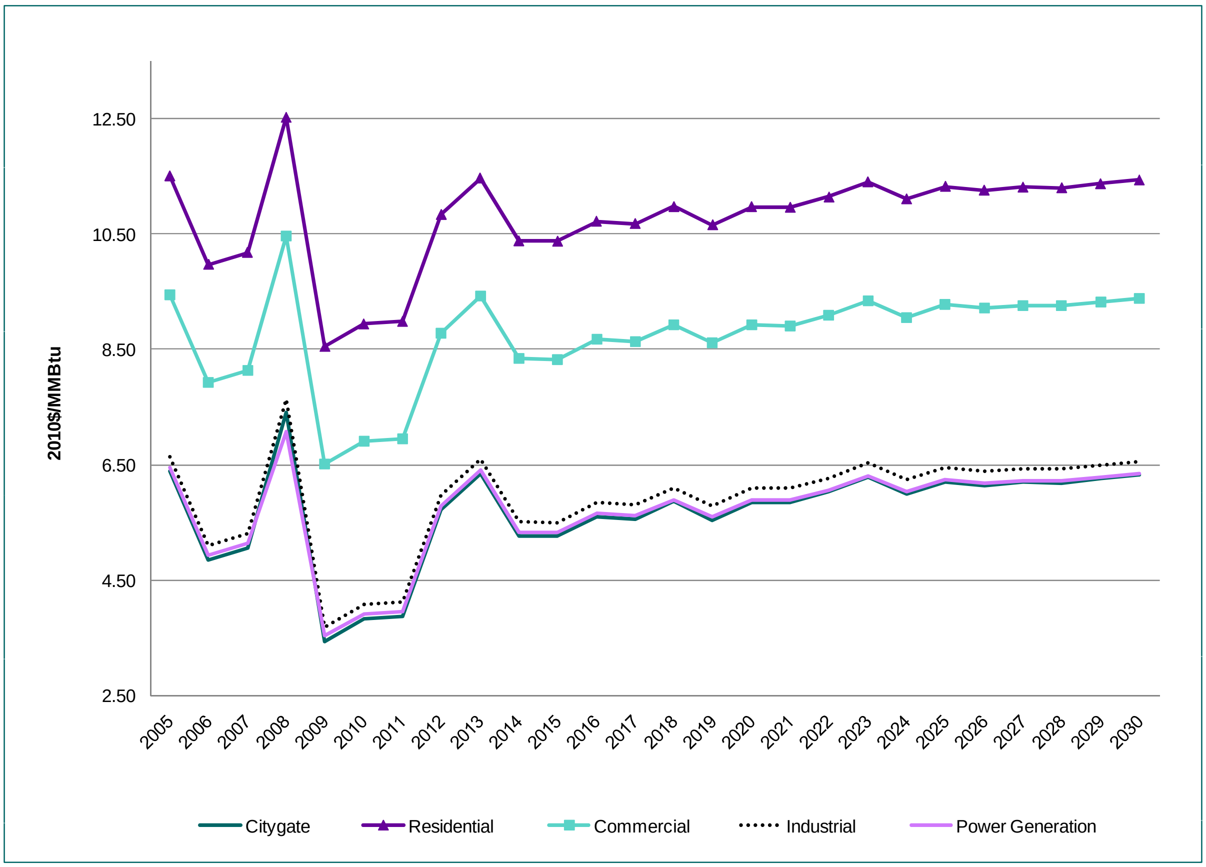
Citygate and End-Use Prices

Figure 28 highlights the differences in delivery costs across customer classes by showing the Reference Case PG&E Citygate price and its associated estimates of residential, commercial, industrial, and electric generation end-use prices. No other cases are shown because transportation costs are held constant among cases.[36] In addition, the end-use transportation

36 This is a simplifying assumption. In reality, differences in market activities included in the WGTM modeling could lead to downstream differences in transportation service and costs.

rates are held constant over time.[37] Residential customers pay for metering infrastructure, administration, and other services that some of the other end-use customers do not. From 2005 through 2030, on average, the residential transportation (distribution) rates make up 48 percent of the total end-use price, while the commercial transportation makes up 36 percent. Industrial and electric generation customers are generally larger end-use customers, and their transportation charges make up a very small portion of their total end-use natural gas price.

Figure 28: PG&E Citygate and End-Use Prices, Reference Case



Source: Energy Commission staff analysis.

Table 26 shows the Reference Case estimates of PG&E total end-use prices and transportation components by sector. The data for this table was taken from the 2010 PG&E

37 This is another simplifying assumption. It implies that future transportation rates increase at the rate of inflation. Significant new investment in transportation facilities, such as pipeline or compressor replacements, could cause transportation rates to increase in real terms.

BCAP.[38] For distribution- and transmission-level service, the PG&E Citygate price was used, while for backbone-level service, the California border price was used. A volume-weighted average border price was used as there are border locations at Malin, Oregon, and Topock, Arizona. The weighting for the average border price was based on natural gas flows into California from each location. Only end users who receive their natural gas from a border location have to pay a backbone rate; citygate price locations already include the backbone rate in their prices.

Table 26: 2010 PG&E End-Use Prices and Transportation Rates, Reference Case

Customer Class	Gas Commodity Cost in 2010 ($2010)	Transmission/ Distribution Rate ($/Dth)	Backbone Rate ($/Dth)	**Total Transportation Rate ($/Dth)	Total End-User Price ($/Dth)
Residential NON-CARE rate –citygate	$3.83	$5.12	N/A	**$5.12**	$8.95
Commercial					
Small Commercial - citygate	$3.83	$3.26	N/A	$3.26	$7.09
Large Commercial - citygate	$3.83	$1.04	N/A	$1.04	$4.87
Volume weighted average commercial rate	**$3.83**		N/A	**$3.07**	**$6.90**
Industrial					
Distribution - Industrial - citygate	$3.83	$1.04	N/A	$1.04	$4.87
Transmission - Industrial - citygate	$3.83	$0.10	N/A	$0.10	$3.93
Backbone - Industrial - border*	$3.63	$0.04	$0.294	$0.34	$3.97
Volume weighted average Industrial rate	**$3.83**		N/A	**$0.89**	**$4.72**
Electric Generation					
Electric Generation - Distribution and transmission - citygate	$3.83	$0.06	N/A	$0.06	$3.89
Electric Generation - Backbone - border*	$3.63	$0.06	$0.294	$0.35	$3.98
Electric Generation-volume-weighted average rate	**$3.75**		N/A	**$0.18**	**$3.93**

Sources: Energy Commission staff analysis.

Rates and Volumes for weighting from: Table K, proposed rates, July 1, 2010 https://www.pge.com/regulation/BCAP-PGE-2009/CPUC/Draft-Decisions/2010/BCAP-PGE-2009_CPUC_Draft-Dec_20100623-01Atch01.pdf

Backbone Rates From Gas Accord V: Appendix A, Table A-1
http://www.pge.com/pipeline/library/regulatory/gasaccord5/ga5settlement.pdf

38 See Table L and Table K at https://www.pge.com/regulation/BCAP-PGE-2009/CPUC/Draft-Decisions/2010/BCAP-PGE-2009_CPUC_Draft-Dec_20100623-01Atch01.pdf.

Border prices are a volume weighted average price of Topock and Malin.

** Total transportation is the sum of backbone, transmission, and distribution.

Note: The 2010 gas commodity cost was used for this example

Residential customers pay the most for transportation services, as seen in **Table 26**; in this example transportation makes up more than 50 percent of the total end-use price of natural gas. Residential end-use customers pay more for transportation (distribution) services because there are more meters to monitor and service, as well as more administrative costs. This table also indicates that transportation rates vary widely across customer classes. The prices in **Table 26** are a snapshot of 2010; staff made no projections of transportation rates going forward.

Uncertainties About Key Variables

As discussed, gas delivery costs are very significant components of total gas prices for residential and commercial customers. Staff's estimates of end-use gas prices relied on sources of information that did not attempt to assess what future transportation component costs could be. A number of current issues suggest that future significant capital investments in transportation infrastructure or increases in operating expenses could occur. Both the scope and magnitude of these potential future transportation cost increases are characterized by considerable uncertainty. Staff made estimates of the potential effect on future transportation cost components of end-use gas prices of the following contingencies:

- Capital investments for pipeline inspection, repair, or replacement in response to public safety concerns about pipeline integrity or environmental contamination.
- Continuation of the Public Purpose Program surcharge.
- Costs of CO_2 allowance obligations on local distribution companies required by the cap-and-trade program of AB 32.
- Pipeline enhancement program costs as a result of San Bruno explosion.

A brief discussion about each subject follows, and an estimate of impact is made.

Increased Capital or Operating Expenses Associated With Public Safety or Environmental Concerns

As introduced in Chapters 2 and 3, concerns about the integrity of the natural gas pipeline system have been raised by the circumstances surrounding the September 2010 gas pipeline explosion in San Bruno. The ongoing inspection program for the state's gas utilities could reveal the need for significant capital investments in pipeline repair or replacement.

Another factor that may lead to changes in the transportation rates of end-use consumers is the U.S. Environmental Protection Agency's (EPA) proposed rulemaking that would limit the amount of polychlorinated biphenlys (PCBs) allowed in natural gas pipelines and compressors. Reducing the amount of PCBs allowed in natural gas pipelines and compressors may require cleaning or replacing pipelines and compressors; the costs for this would ultimately be paid by ratepayers. The Interstate Natural Gas Association of America (INGAA) estimates that the total cost to the United States to comply with the U.S. EPA's rule on PCBs would range from $33 billion to $466 billion (nominal) in 2020.[39] These costs are not insignificant.

When pipelines or compressors are replaced or repaired, the cost will generally, but not always or totally, fall to ratepayers. Staff computed an estimate of how much more ratepayers might pay to recover $500 million and $1 billion in capital costs for pipeline replacements. This calculation looks at the PG&E system and assumes the cost of the new pipelines is spread over 20 years, the PG&E system has 2,200 MMcf/d of flowing supply, the utility receives a 10 percent rate of return, and the costs are spread evenly to each end-use demand sector. **Table 27** and **Table 28** illustrate this calculation.

Table 27: Yearly Transportation Rate Increase With $500 Million in New Pipeline Costs

	Current Rate	Increase	Total	Percent Change
Residential	$5.48	$0.22	$5.80	4%
Industrial	$1.52	$0.06	$1.58	4%
Electricity Generation	$0.55	$0.02	$0.57	4%

Source: Energy Commission staff analysis.

Table 28: Yearly Transportation Rate Increase With $1 Billion in New Pipeline Costs

	Current Rate	Increase	Total	Percent Change
Residential	$5.48	$0.44	$6.02	8%
Industrial	$1.52	$0.12	$1.64	8%
Electricity Generation	$0.55	$0.04	$0.59	8%

Source: Energy Commission staff analysis.

39 See http://www.ingaa.org/File.aspx?id=10757 page 21.

An estimate of the cost to California ratepayers of complying with the U.S. EPA's PCB rule can be calculated as in **Table 28**. Using the low estimate compliance cost of $33 billion, and taking 10 percent of this cost (the population in California is roughly 10 percent of the United States population) yields an estimated California cost of $3.3 billion. If the cost in California to replace or upgrade pipelines and compressors is $3.3 billion, and assuming every $1 billion spent on pipeline replacements equals an 8 percent increase in rates to all customer classes, a 26.4 percent increase in transportation rates would be expected. The costs in **Table 28** are for 2010 while the costs from the INGAA study are for 2020. This is just an estimate to show the potential magnitude that such a policy decision could have on natural gas transportation rates.[40]

Public Purpose Program Surcharge

The Public Purpose Program (PPP) surcharge is collected to fund specific low-income, energy efficiency, conservation, and public interest energy research.[41] Since this surcharge is a component of the natural gas distribution rate for nonelectric generation end-use sectors for each California utility, the fate of this surcharge can affect those gas customers' prices. There are a number of bills in the California Legislature potentially affecting this program. Assembly Bill 723 (Bradford, Statutes of 2011) would extend a portion of the PPP surcharge through 2020.[42] If the bill does not pass, end-use gas transportation rates would likely decline.

Table 29 shows the total transportation rates and PPP rate components for PG&E in its July 2010 proposed rates.[43] These transportation rates differ slightly from staff's end-use estimates because of rounding and how each demand sector is classified. All rates in **Table 29** are in nominal $/MMBtu. **Table 29** indicates that the PPP surcharge makes up a substantial portion of the total transportation rate; in this example, 87 percent of the total transportation rate for backbone level industrial end-use customers. This example illustrates the relative magnitudes of the natural gas PPP surcharges for different customer classes; the PPP surcharge may change from year to year.

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40 The CPUC has Rulemaking (R11-02-019) proceeding to test and replace pipeline infrastructure http://docs.cpuc.ca.gov/proceedings/R1102019.htm. PG&E and SoCal Gas/SDG&E presented estimates of rate impacts of gas infrastructure replacement at the December 1, 2011, Natural Gas Stakeholders meeting at the Energy Commission. http://www.energy.ca.gov/naturalgas/documents/2011-12-01_meeting/.

41 For more on the PPP surcharge see http://www.pge.com/tariffs/tm2/pdf/GAS_SCHEDS_G-PPPS.pdf.

42 See http://info.sen.ca.gov/pub/11-12/bill/asm/ab_0701-0750/ab_723_cfa_20110624_094903_sen_comm.html for more on AB 723. This bill did not pass the Senate on June 29, 2011, but was referred back to the Committee on Energy, Utilities, and Commerce.

43 https://www.pge.com/regulation/BCAP-PGE-2009/Testimony/PGE/2009/BCAP-PGE-2009_Test_PGE_20090529-01.pdf Table 5-A.

Table 29: PG&E's Public Purpose Program Surcharge

Customer Class	PPP Surcharge	Total Transportation Rate	PPP Percent of Total Transportation Rate
Residential Non-CARE	$0.65	$5.730	11%
Small Commercial Non-CARE	$0.44	$3.870	11%
Large Commercial	$0.69	$1.920	36%
Industrial - Distribution	$0.38	$1.460	26%
Industrial - Transmission	$0.33	$0.570	58%
Industrial - Backbone	$0.33	$0.380	87%
Electric Generation - Transmission	N/A	$0.059	N/A
Electric Generation - Backbone	N/A	$0.059	N/A

Source: https://www.pge.com/regulation/BCAP-PGE-2009/Testimony/PGE/2009/BCAP-PGE-2009_Test_PGE_20090529-01.pdf Table 5-A.

Cost of Greenhouse Gas Emission Allowance Obligation of Assembly Bill 32 Cap-and-Trade Program

Another potential driver of natural gas end-use price is AB 32 carbon allowance costs. Starting in 2015, deliverers of natural gas not already covered by the cap-and-trade program will need to have CO_2 allowances to cover their emissions. This obligation will fall to local gas distribution companies. The allowance costs will, at least partly, be passed on to residential and commercial gas consumers. There are uncertainties in these carbon allowance costs such as how many allowances will be allocated for free rather than auctioned, how the bidding in the auctions will work, how the money collected from the allowances will be used, and at what price the allowances will trade. These uncertainties can greatly affect the cost of carbon allowances.

The Brattle Group found in its study of AB 32's potential effects on small businesses that carbon allowance costs could increase natural gas prices by $1.50 – $3.00 per decatherm (Dth) (1 Dth = 1MMBtu) or 12 percent to 25 percent in 2020.[44] Staff calculated carbon allowance costs to get a ballpark estimate of how carbon allowance costs could affect natural gas prices. This calculation assumes the minimum (reserve) allowance price and that 50 percent of the allowances are free and 50 percent are auctioned. The emission factor assumed for all sectors is 5.31^{E-08} million metric tons carbon dioxide equivalent per million Btu ($MMTCO_2e$/MMBtu). This is equivalent to 119 lbs CO_2/MMBtu, the value commonly

44 See http://www.ucsusa.org/assets/documents/global_warming/AB-32-and-CA-small-business-report.pdf.

used within the Energy Commission's Electricity Analysis Office [45]. These prices are an estimate of what commercial and residential customers pay on top of their natural gas rates. Due to the inherent uncertainties in the carbon allowances, their cost could end up higher or lower than what has been estimated. **Table 24** summarizes the carbon allowance cost calculation performed by staff. All the prices in **Table 24** are in real terms, and adding the minimum carbon allowance cost to the Reference Case PG&E Citygate prices yields an increase of between 5 percent and 10 percent.

Potential Impacts of San Bruno Incident

On September 9, 2010, a 30-inch-diameter, high-pressure natural gas transmission pipeline exploded under a neighborhood street in San Bruno, California. The explosion of Line 132, owned by PG&E, killed 8 people and destroyed 37 homes. The CPUC and the National Transportation Safety Board (NTSB) both launched investigations into the explosion.

Among the early findings by the NTSB was a longitudinal seam on a segment of Line 132 failed, while PG&E had indicated that the segment was seamless. As a result, the NTSB encouraged and the CPUC ordered PG&E to begin searching for "traceable, verifiable and complete" records to confirm the features and maximum allowable operating pressure (MAOP) of its pipelines in "High Consequence Areas" (HCAs). The NTSB released the Pipeline Accident Report on August 10, 2011.[46] In the report the NTSB identified a substandard and poorly welded pipe section that eventually led to the rupture of the pipeline. The CPUC also ordered PG&E to reduce operating pressures on lines of similar vintage and characteristics to Line 132 located in HCAs by 20 percent below MAOP. Subsequent additional pressure reductions have either been ordered by the CPUC or implemented voluntarily by PG&E on additional lines, some in conjunction with hydrostatic testing that PG&E is conducting this year on 152 miles of pipeline for which it could not find records to validate MAOP.

In June 2011, the CPUC issued an order as part of Order Instituting Rulemaking (OIR) 11-02-019 into new pipeline safety rules, directing PG&E, SoCalGas, San Diego Gas & Electric (SDG&E) and Southwest Gas to pressure test or replace all pipelines, not just those in HCAs, for which the operators do not have "traceable, verifiable and complete" records of MAOP.[47] This testing is expected to take several years. Until this is complete, the utilities will adopt appropriate interim safety measures that include enhanced patrolling and leak survey. As utilities pursue the extensive examination of pipeline system records, conduct hydrostatic testing, and replace pipeline, customers may experience reduced system pressures and capacity as well as occasional outages. The CPUC directed the noted utilities

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45 See http://www.epa.gov/cpd/pdf/brochure.pdf.

46 http://www.ntsb.gov/investigations/summary/PAR1101.html

47 http://docs.cpuc.ca.gov/proceedings/R1102019.htm

to prepare pipeline safety enhancement plans for their respective systems to describe how the pipeline testing would be carried out along with other safety enhancement measures.

On June 30, 2011, PG&E released results of a "Class Location Study." The Class Location Study found that several of PG&E's pipelines were misclassified. The classifications are used to help set MAOP based on the pipeline segment's proximity to homes and businesses. To immediately remedy the misclassifications, PG&E reduced operating pressures on several additional pipeline segments.

On August 26, 2011, PG&E filed its Pipeline Safety Enhancement Plan as required by the CPUC. The first phase of the plan will run from 2011 to 2014 and calls for pipeline modernization, valve automation, records integration, and interim safety measures. The cost of the plan is estimated to be $2.2 billion over the next four years, and it remains to be seen how costs will be recovered pending CPUC approval of the plan. PG&E has already started work on the plan (pipeline testing and replacement), and costs incurred in 2011 will be borne by shareholders. All stakeholders will be given a chance to comment on PG&E's plan as part of the rulemaking procedure. A final decision on the plan from the CPUC is expected by June 2012.

SoCalGas and SDG&E also submitted their joint Pipeline Safety Enhancement Plan on August 26, 2011. The plan consists of several component phases with Phase 1A expected to extend from 2012 to 2015. Phase 1A calls for pipeline modernization, valve automation, enhanced incident detection and damage avoidance, and the development of a "blueprint" of a comprehensive asset management system. The direct cost of the plan for both SoCalGas and SDG&E is estimated to be about $1.6 billion (Phase 1A). Phase 1B will continue work started in Phase 1A and will span from 2015 to 2021 costing about $1.4 billion. The plan is still waiting for CPUC final approval as part of the rulemaking process.

There are several potential impacts to customers from the lower operating pressures and testing. First, reducing operating pressure in a pipeline effectively reduces the amount of natural gas that can be delivered through that pipeline in a given period. To the extent that lower pressures are below the pressures needed to support deliveries under PG&E's original temperature design criteria, customer curtailments can result. To date, PG&E has reported no curtailments to customers as a result of reducing the MAOP to pressures consistent with the location class study. However, in an October 2010 letter to the CPUC, PG&E identified conditions, including conditions warmer than those known as a Cold Winter Day, under which service to customers on the San Francisco peninsula could be affected.[48] Cold Winter Day conditions are defined by PG&E to occur once every two years. In that letter, PG&E also identified steps it could implement in terms of operations or the addition of cross-ties between certain lines that would reduce the probability of potential curtailments. PG&E has not yet released an update of this analysis for winter 2011 – 2012,

48 The letter, from PG&E's Brian Cherry to CPUC Executive Director Paul Clanon, can be found at: http://www.cpuc.ca.gov/NR/rdonlyres/6A94E6D5-7DE1-40EE-9461-ADC116A17707/0/Oct25PGEResponsetoCPUC.pdf.

but the CPUC has confirmed to staff that the steps it identified last winter were implemented.

In addition, the lower pressures reduce PG&E's daily operating flexibility. This flexibility is embodied in what PG&E calls "pipeline system inventory." The inventory defines a range of minimum and maximum amounts of natural gas that PG&E needs to or can hold in the pipeline system without affecting service. Normally that range is 600 MMcf/d and provides an operational cushion to absorb imbalances between customer deliveries and actual daily usage. When inventory gets close to the minimum or maximum levels, PG&E issues an "operational flow order" (OFO) directing its customers to better balance their deliveries into the system with their usage. Normally a high inventory OFO occurs when too many customers have delivered more gas into the system than they have used or injected into storage; conversely, a low-inventory OFO occurs when customers use more gas than they delivered into the system or withdrew from storage. Customers were allowed to be out of balance in the opposite direction of the OFO since using excess gas when the system is over-pressured, for example, would help reduce the high pressure causing the OFO.

With the additional pressure reductions necessitated by the findings of the Class Location Study, PG&E's 600 MMcf/d permissible inventory swing has become only 200 MMcf/d. PG&E beginning on July 1 and until about December 1, 2011, issued high- and low-inventory OFO simultaneously, every day. These simultaneous daily OFOs mean that customers must match their deliveries of gas into the PG&E system on both the high and low sides of their daily usage. In the meantime, staff is monitoring for market effects of the tighter balancing. As of December 1, 2011, PG&E returned the inventory swing to 450 MMcf/d, eliminating the need for simultaneous high and low OFOs.

Hydrostatic testing means taking the segment of line being tested out of service. Testing typically takes several days. If the test causes the pipeline to fail, then it must be replaced, during which time the segment remains out of service. It appears that for most of the segments being tested in 2011, PG&E has the ability to reroute natural gas to continue service to nearby customers. Certain very large customers, such as gas-fired electricity generating plants, take service directly from high-pressure transmission pipelines. The Energy Commission is aware that service to certain power plants may be affected, and staff is working with its sister agencies to provide information and contingency planning support to address potential outages.

The flow reduction due to lower operating pressures (on what is known as the "backbone" portion of PG&E's transmission system) amounts to a loss in flow capability of about 500 MMcf/d. In summer months, this capacity is often used to help fill underground gas storage. Gas in storage is essential to meeting California's winter month gas requirements. Staff's analysis to date leads to the encouraging conclusion that PG&E should be able to inject into storage most, if not all, of the gas it needs to protect service to core customers even with the reduced operating pressures and lower gas flows.

Staff looked at whether the reduction in lower backbone transmission availability could affect the state's ability to meet all natural gas demand. As a first cut, staff assessed capacity available to serve monthly average daily demand under normal weather conditions in what is known as a *gas balance analysis*. This involved taking PG&E's projection of annual demand in a normal year (obtained from the *2010 California Gas Report*) and spreading it across months using annual to monthly spread factors calculated from a series of recorded monthly demands. Using six years of recorded monthly demand, staff calculated a factor that describes demand in each month on the PG&E system as a percentage of average annual demand. These demands are an imperfect proxy for PG&E demand forecasted by month in a normal weather condition year. Using this monthly demand spread, and projected backbone capacity availability as posted on PG&E's Pipe Ranger, the analysis suggests that PG&E's natural gas capacity reserve margin could be pushed to very close to zero in December and January.

Looking at average daily demand in a month can be misleading without realizing that, as demand swings up and down around that average day, PG&E has the flexibility to withdraw much more gas from storage on a given day that it cannot sustain for every day over a month or over a winter. For example, the analysis assumed average daily withdrawals of 350 MMcf/d in December, but on a specific cold day PG&E can withdraw upwards of 1,100 MMcf/d. In addition, noncore customers should be able to withdraw some amount of gas from third-party storage that PG&E can accept into its local transmission system rather than into its backbone system, and a small piece of any difference might be absorbed in pipeline system inventory. This assumes, however, that noncore customers fill their storage. Noncore customers did not fully fill their storage inventories during summer and fall 2000, which contributed to natural gas price impacts that winter as the electricity crisis unfolded. As customers prepare for winter 2011 – 2012, noncore customers would be prudent to use available backbone capacity to inject as much gas as possible into storage.

Staff then looked at what would happen under colder conditions, including under WPD conditions, to assess the effect of pressure reductions on natural gas service. PG&E projects demand under WPD conditions of 4,270 MMcf/d and notes in the *2010 California Gas Report* that WPD conditions have a recurrence probability of 1-in-35 years. The capability to serve WPD demand and a comparison to two cold days with demand close to WPD from December 2009 are shown in **Table 30**. Larger than average day withdrawals from storage by PG&E were required to meet demand on these days. On the two cold days in 2009, noncore customers chose to pull gas from storage and used that gas in lieu of out-of-state supplies delivered via backbone capacity. In looking at the WPD, staff assumed that customers would make full use of available backbone capacity and that PG&E would withdraw 1,100 MMcf/d of gas from storage—1,100 MMcf/d is intentionally smaller than what PG&E withdrew on the cold days shown from 2009, leaving a small contingency margin. Making full use of backbone capacity constrained by the pressure reduction means that some gas must come from independent storage to serve all demand. The importance of filling not only PG&E storage, but independent storage, to make up for the constrained backbone capacity on days colder than average conditions occur is clear. Customers who have access to those independent storage facilities would be prudent to use available backbone capacity to inject gas this fall and to include in their winter 2011 – 2012 contingency planning an expectation that they may need to use their stored gas for reliability purposes.

Table 30: PG&E High Demand Day Gas Requirements and Sources

MMcf/d	Dec 8 2009 Recorded	Dec 9 2009 Recorded	Winter Peak Day Forecast From 2010 California Gas Report[/1]
Demand			
Core	2,840	2,926	2,850
Industrial	677	692	420
Electric Generation	551	528	1,000
Off-System	27	68	0
Total	4,095	4,214	4,270
Capacity & Supply			
Redwood	901	809	1,800[/2]
Baja	1,031	1,051	733
Silverado (CA Production)	120	120	130
PG&E Storage	1,344	1,228	1,100
Independent Storage	699	1,006	507
Total	4,095	4,214	4,270

Source: Compilation of data reported on PG&E Pipe Ranger, *California Gas Report*, and staff analysis.

1. The capacity and supply data shown are Energy Commission staff projections, updated for PG&E notices on its Pipe Ranger website. See http://www.pge.com/pipeline/operations/pipeline_maintenance/foghorn.shtml.

2. Ruby Pipeline feeds into the Redwood path. PG&E has noted in previous *California Gas Reports* that under very cold conditions it often sees a diminution in supply delivered to the California border. Achieving deliveries of 1,800 MMcf/d on a cold day seems reasonable given the new supply offered from Ruby.

This analysis does not look at potential local area curtailments. PG&E requested expedited review of proposed pipeline pressure restoration on key Bay Area lines before winter. A formal report on hydrotesting efforts and preliminary results were presented in an evidentiary hearing on November 22, 2011; the CPUC issued a decision on December 15 to restore pressure on lines 101, 132A, and 147.

PG&E has been steadily restoring pipeline capacity and available inventory as pipe segments have been cleared through testing. As of Monday, November 28, 2011, system capacity along the Redwood Path was at 2,130 MMcf/d – which is 98 percent of maximum capacity. System capacity along the Baja Path was operating at 72 percent of maximum capacity (822 MMcf/d). PG&E reports that as of December 5, 2011, available system inventory stands at 4,361 MMcf – an increase from 2,000 MMcf due to pipeline testing. The increase in inventory is expected to eliminate the need to call high/low inventory OFOs. However it is expected that that calls for one-sided OFOs will continue on an ongoing basis as necessary. On November 4, 2011, PG&E reported that Northern California's storage inventory levels were higher than they have been in the last three years for this point in time of the storage season. Therefore, PG&E expects no limitations in regular withdrawal capabilities for the storage facilities located in PG&E's system this winter.

CHAPTER 5: Post-Workshop Sensitivity Analyses of Future Natural Gas Prices

This chapter discusses six new sensitivity cases staff conducted in response to comments made by parties at the September 27, 2011, workshop on the August 2011 staff draft report *Natural Gas Market Assessment: Outlook*,[49] or in subsequent written comments. Comments of parties that are not addressed by these sensitivity cases are discussed in Appendix F. Rather than revise Chapter 3 to include these results, Chapter 3 remains essentially the same as in the September 2011 Draft. However, typos and errors have been corrected.[50] Therefore, this chapter presents the most complete discussion of price results in staff's market assessment.

Comments Focused on Staff's Narrow Range of Prices

The new sensitivity studies staff conducted respond to comments that parties made about staff's modeling results for expected natural gas spot market price. Staff intended the price results from the High and Low Gas Price Cases discussed in Chapters 2 and 3 to describe a wide plausible range of expected annual average prices of spot market natural gas at Henry Hub. However, many parties commented that the range of Henry Hub prices across the cases seemed narrower than they would have expected. Discussion at the workshop and subsequent written comments identified staff's assumptions about a number of key drivers that merit additional scrutiny. These include:

- The amount of natural gas that is technically recoverable, which generally grows over time in response to technology innovation.
- The amount of natural gas that is economically recoverable, which grows with either decreasing costs of producing gas or rising prices paid for gas.
- The stringency of environmental restrictions, which either increase variable costs of producing gas or constrain the supply of gas by restricting access to some plays.
- The demand for natural gas, which increases with economic growth and is variably affected by environmental and energy policies affecting electric generation, especially those encouraging coal-fired power plant conversions.

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49 Publication CEC-200-2011-011-SD.

50 At the September 27, 2011, workshop, staff acknowledged that the High and Low CA Gas Demand Cases had not been executed exactly as described in Chapter 2. Since then, staff has rerun those cases and replaced the original text, tables, and figures that refer to those cases with updated versions.

Scope of Sensitivity Studies to Widen Range of Prices

The overall design of staff's post-workshop analysis is essentially a bounding exercise. [51] How high (or low) might annual average equilibrium gas prices go given more extreme input assumptions about the future states of key drivers of prices? Staff developed four single variable sensitivity cases and two multivariable sensitivity cases. The four new single-variable sensitivity cases make a different, more extreme assumption about a key driver—the overall F&D environment—to test its effect on the starting case's resulting prices, moving them toward an upper or lower bound. These sensitivity cases are named below, followed by sections further discussing of the rationale and details of their construction. See Appendix D for a complete description of the probabilities levels.

- **Sensitivity Case I**: Staff used the Reference Case assumptions. However, the overall F&D environmental costs are increased from an expected level (P50) to a very high level that has only been reached or exceeded during 10 percent of the historical record (P10).
- **Sensitivity Case II:** Staff used the Reference Case assumptions. However, the overall F&D environmental costs are decreased from an expected level (P50) to a very low level that has been exceeded during 90 percent of the historical record (P90). Alternately, an overall cost environment this low or lower has only been observed during 10 percent of the historical record.
- **Sensitivity Case III:** Staff used the Low Gas Price Case assumptions. However, the overall F&D environmental costs are decreased to the low P90 level.
- **Sensitivity Case IV**: Staff used the High Gas Price Case assumptions. However, the overall F&D environmental costs are increased to the high P10 level.

Two other sensitivity cases were designed to see how much higher those prices might go by successively adding higher environmental mitigation costs, and then adding additional electric generation gas demand, driven by an assumption of additional conversions of coal-fired generation capacity to natural gas.

- **Sensitivity Case V**: Starting with Sensitivity Case IV, an additional $0.30/Mcf is added to the O&M cost for more stringent environmental mitigation, in particular, water handling. This results in total environmental mitigation costs being $0.70/Mcf higher in this case than assumed in the Reference Case.
- **Sensitivity Case VI**: Starting with Sensitivity Case V, an additional 40 GW of coal-fired generation capacity retirement is assumed, replacing that electricity supply with natural gas-fired generation. This results in total coal-fired capacity retirements being 90 GW higher in this case than assumed in the Reference Case.

51 Finding bounds of long-term annual average equilibrium price, not market price at any given season or time as may be affected by short-term demand or supply changes (due to weather, hurricanes, and so forth.)

A short summary of assumptions used in the model and the results and differences across the sensitivity cases for 2022 and 2030 are represented in **Table 31** and **Table 32.**

Table 31: Summary of World Gas Trade Model Key Driver Assumptions and Results for Sensitivity Cases, 2022

	Reference Case	Sensitivity Case I	Sensitivity Case II	Sensitivity Case III	Sensitivity Case IV	Sensitivity Case V	Sensitivity Case VI
Results in 2022							
DEMAND							
US Tcf/yr	25.30	22.18	28.2	28.99	22.47	22.01	22.57
US Gas-Fired Electricity Generation Tcf/yr	8.47	7.52	9.33	9.43	8.45	8.29	8.87
CA Tcf/yr	2.19	1.94	2.43	2.49	1.91	1.87	1.86
CA Gas-Fired Electricity Generation Tcf/yr	0.65	0.58	0.72	0.73	0.60	0.59	0.59
SUPPLY							
US Natural Gas Dry Production Tcf/yr	24.78	22.36	27.00	27.71	19.93	18.90	19.36
US Shale Tcf/yr	12.23	10.88	12.83	14.73	7.93	6.85	7.33
US LNG Tcf/yr	1.07	1.07	1.07	1.07	1.07	1.07	1.07
Canadian Imports Tcf/yr	3.48	2.22	4.61	4.48	3.16	3.22	3.16
Exports Tcf/yr	2.5	2.24	2.82	2.60	2.16	2.39	2.43
PIPELINE CAPACITY							
Cumulative New Capacity to CA (Tcf) (aggregated from 2010 to 2022)	0.08	0.14	0.09	28.09	0.02	0.15	0.12
Pipeline Utilization; % of total (EPNG+TW+MJ/ GTN/ KRGT/ Ruby)*	36.82/68.46/ 72.87/47.72	33.3/53.28 61.04/50.46	39.32/85.94 78.08/44.29	38.68/90.76 80.37/42.24	32.57/49.83 60.12/51.83	31.93/49.83 53.01/47.95	32.37/46.79 55.25/48.40
PRICES							
Price at Henry Hub ($2010)/MMBtu	5.63	6.62	4.67	4.47	7.13	7.21	7.13
Basis to CA Border at Topock ($2010)/MMBtu	0.26	0.31	0.19	0.21	0.35	0.37	0.35
Basis to Malin ($2010)/MMBtu	-0.08	0.05	-0.13	-0.11	0.08	0.09	0.10

*El Paso Natural Gas (EPNG) Transwestern (TW) Mojave (MJ) TransCanada Gas Transmission Northwest (GTN) Kern River Gas Transmission (KRGT) Ruby Pipeline (Ruby) CA (California)

Table 31: Summary of World Gas Trade Model Key Driver Assumptions and Results for Sensitivity Cases, 2022 (Continued)

	Reference Case	Sensitivity Case I	Sensitivity Case II	Sensitivity Case III	Sensitivity Case IV	Sensitivity Case V	Sensitivity Case VI
Key Assumptions							
Average Annual GDP Growth Rate	2.6%	2.6%	2.6%	2.1%	3.5%	3.5%	3.5%
Gas Technology Improvement Average Annual Growth Rate	1%	1%	1%	1%	1%	1%	1%
Total US Electricity Production (GWh)	4,766,558	4,766,558	4,766,558	4,735,485	4,819,407	4,819,407	4,819,407
US Electricity Resource Mix (% of total from Fossil/Nuclear/Hydro/Renew)	66.8/17.8/ 5.45/15.37	66.8/17.8/ 5.45/15.37	66.8/17.8/ 5.45/15.37	65.6/17.8/ 5.5/16.6	68.8/17.8/5.4/ 13.4	68.8/17.8/5.4/ 13.4	68.8/17.8/5.4/ 13.4
Total CA Electricity Production (GWh)	238,058	238,058	238,058	236,506	240,698	240,698	240,698
CA Electricity Resource Mix (% of total from Fossil/Nuclear/Hydro/Renew)	44.5/14.5/ 11.5/29.4	44.5/14.5/ 11.5/29.4	44.5/14.5/ 11.5/29.4	44.3/14.5/ 11.6/29.6	45.0/14.5/ 11.4/29.1	45.0/14.5/ 11.4/29.1	45.0/14.5/ 11.4/29.1
When CA Meets Maximum RPS Target	On Time	On Time	On Time	On Time	On Time	On Time	On Time
When Other States Meet Individual Maximum RPS Targets	5 yrs late	5 yrs late	5 yrs late	On Time	10 yrs late	10 yrs late	10 yrs late
Additional US Coal Generation Converts to Natural Gas	0	0	0	0	50 GW	50 GW	90 GW
Constrain/Augment Natural Gas Resources							
US	NY	NY	NY	Upper End of Range	PA, NY, CO and WY	PA, NY, CO and WY	PA, NY, CO and WY
World	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]	IIRV Constrained[1]	IIRV Constrained[1]	IIRV Constrained[1]
LNG Exports	Allowed but not imposed	Allowed but not imposed	Allowed but not imposed	Allowed but not imposed	Imposed LNG Exports	Imposed LNG Exports	Imposed LNG Exports
Pipeline Capacity Additions (Model feature turned On/Off)	ON	ON	ON	ON	ON	ON	ON
PG&E Backbone Capacity Reduction Constraint, MMcf/d	None	None	None	None	None	None	None
Additional Environmental Mitigation Cost ($2005/Mcf)	N/A	N/A	N/A	N/A	$0.40/Mcf shale $0.20/Mcf Conv	$0.70/Mcf	$0.40/Mcf shale $0.20/Mcf Conv
Cost Environment	P50	P10	P90	P90	P10	P10	P10

Source: California Energy Commission staff draft analysis
1 Note: IIRV refers to Iran, Iraq, Russia, and Venezuela.
2 Note: IIV refers to Iran, Iraq, and Venezuela.
3 Note: Capacity additions off for years 2012 – 2016.
4 Note: Continues to grow to 40 percent by 2027 and then stabilizes.

Table 32: Summary of World Gas Trade Model Key Driver Assumptions and Results for Sensitivity Cases, 2030

	Reference Case	Sensitivity Case I	Sensitivity Case II	Sensitivity Case III	Sensitivity Case IV	Sensitivity Case V	Sensitivity Case VI
Results in 2022							
DEMAND							
US Tcf/yr	27.58	24.12	30.93	33.18	25.14	24.60	25.50
US Gas-Fired Electricity Generation Tcf/yr	9.47	8.36	10.54	11.13	9.94	9.73	10.64
CA Tcf/yr	2.31	2.03	2.57	2.76	2.05	1.99	1.99
CA Gas-Fired Electricity Generation Tcf/yr	0.66	0.58	0.73	0.77	0.62	0.61	0.61
SUPPLY							
US Natural Gas Dry Production Tcf/yr	24.78	22.69	28.48	31.58	21.99	20.82	21.86
US Shale Tcf/yr	12.23	12.42	15.17	18.61	9.60	8.65	9.67
US LNG Tcf/yr	1.07	1.17	1.17	1.17	1.17	1.17	1.17
Canadian Imports Tcf/yr	3.48	3.72	5.48	5.33	3.96	4.32	4.21
Exports Tcf/yr	2.5	2.56	2.68	2.94	1.87	1.97	2.12
PIPELINE CAPACITY							
Cumulative New Capacity to CA (Tcf) (aggregated from 2010 to 2022)	0.19	0.17	0.35	45.67	0.16	0.15	0.12
Pipeline Utilization; % of total (EPNG+TW+MJ/ GTN/ KRGT/ Ruby)*	35.8/92.3 66.3/28.3	34.42/78.51 61.04/32.19	38.38/95.08 68.80/34.70	41.91/95.05 80.37/42.24	34.57/60.40 54.64/45.43	31.93/49.83 54.03/39.04	31.64/63.85 52.51/40.41
PRICES							
Price at Henry Hub ($2010)/MMBtu	6.15	7.07	5.30	4.37	7.54	7.63	7.67
Basis to CA Border at Topock ($2010)/MMBtu	0.282	0.35	0.24	0.17	0.33	0.34	0.42
Basis to Malin ($2010)/MMBtu	-0.145	-0.12	-0.11	-0.14	0.01	-0.06	0.06

*El Paso Natural Gas (EPNG) Transwestern (TW) Mojave (MJ) TransCanada Gas Transmission Northwest (GTN) Kern River Gas Transmission (KRGT) Ruby Pipeline (Ruby) CA (California)

Table 32: Summary of World Gas Trade Model Key Driver Assumptions and Results for Sensitivity Cases, 2030 (Continued)

	Reference Case	Sensitivity Case I	Sensitivity Case II	Sensitivity Case III	Sensitivity Case IV	Sensitivity Case V	Sensitivity Case VI
Key Assumptions							
Average Annual GDP Growth Rate	2.6%	2.6%	2.6%	2.1%	3.5%	3.5%	3.5%
Gas Technology Improvement Average Annual Growth Rate	1%	1%	1%	1%	1%	1%	1%
Total US Electricity Production (GWh)	4,766,558	4,766,558	4,766,558	4,735,485	4,819,407	4,819,407	4,819,407
US Electricity Resource Mix (% of total from Fossil/Nuclear/Hydro/Renew)	66.8/17.8/ 5.45/15.37	66.8/17.8/ 5.45/15.37	66.8/17.8/ 5.45/15.37	65.6/17.8/ 5.5/16.6	68.8/17.8/5.4/ 13.4	68.8/17.8/5.4/ 13.4	68.8/17.8/5.4/ 13.4
Total CA Electricity Production (GWh)	238,058	238,058	238,058	236,506	240,698	240,698	240,698
CA Electricity Resource Mix (% of total from Fossil/Nuclear/Hydro/Renew)	44.5/14.5/ 11.5/29.4	44.5/14.5/ 11.5/29.4	44.5/14.5/ 11.5/29.4	44.3/14.5/ 11.6/29.6	45.0/14.5/ 11.4/29.1	45.0/14.5/ 11.4/29.1	45.0/14.5/ 11.4/29.1
When CA Meets Maximum RPS Target	On Time	On Time	On Time	On Time	On Time	On Time	On Time
When Other States Meet Individual Maximum RPS Targets	5 yrs late	5 yrs late	5 yrs late	On Time	10 yrs late	10 yrs late	10 yrs late
Additional US Coal Generation Converts to Natural Gas	0	0	0	0	50 GW	50 GW	90 GW
Constrain/Augment Natural Gas Resources							
US	NY	NY	NY	Upper End of Range	PA, NY, CO and WY	PA, NY, CO and WY	PA, NY, CO and WY
World	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]	IIRV Constrained[1]	IIRV Constrained[1]	IIRV Constrained[1]
LNG Exports	Allowed but not imposed	Allowed but not imposed	Allowed but not imposed	Allowed but not imposed	Imposed LNG Exports	Imposed LNG Exports	Imposed LNG Exports
Pipeline Capacity Additions (Model feature turned On/Off)	ON	ON	ON	ON	ON	ON	ON
PG&E Backbone Capacity Reduction Constraint, MMcf/d	None	None	None	None	None	None	None
Additional Environmental Mitigation Cost ($2005/Mcf)	N/A	N/A	N/A	N/A	$0.40/Mcf shale $0.20/Mcf Conv	$0.70/Mcf	$0.40/Mcf shale $0.20/Mcf Conv
Cost Environment	P50	P10	P90	P90	P10	P10	P10

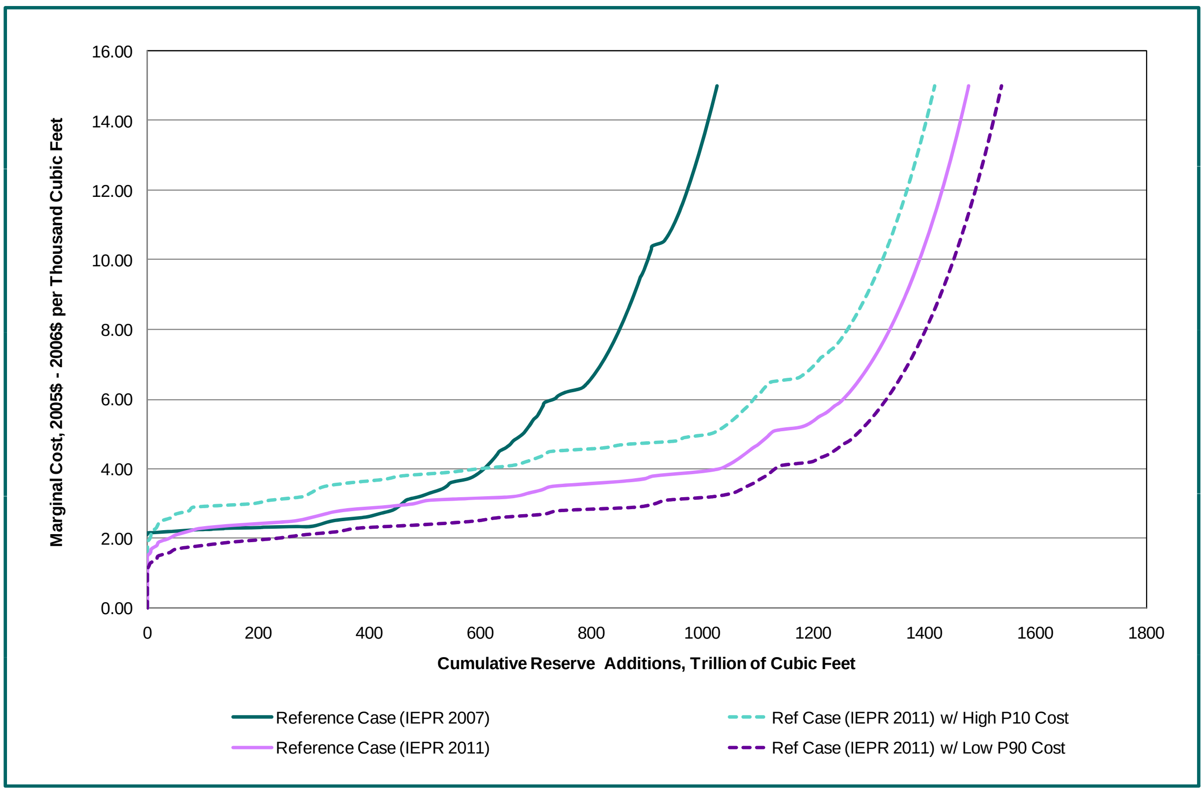
Source: California Energy Commission staff draft analysis
1 Note: IIRV refers to Iran, Iraq, Russia, and Venezuela.
2 Note: IIV refers to Iran, Iraq, and Venezuela.
3 Note: Capacity additions off for years 2012 – 2016.
4 Note: Continues to grow to 40 percent by 2027 and then stabilizes.

Rationale for Finding and Development Costs Sensitivities

The rationale for and detail of constructing Sensitivity Cases I – IV are fully explained in Appendix D: Estimating Natural Gas Reserves and Marginal Production Costs. This section gives a briefer overview. Parties at the workshop commented that staff's assumed marginal capital cost curves for the Reference Case and the High and Low Gas Price Cases (see **Figure D-5** in Appendix D and **Figure 29**) are so "flat" that demand for gas would have to change significantly for price to be affected. Even though many parties thought staff examined a plausible range of gas demand levels across the cases, the resulting gas price range seemed too narrow. As mentioned above, the assumed marginal production cost curves are the result of the interaction of two assessments:

- The amount of natural gas that is technically recoverable, which generally grows over time in response to technology innovation.
- The amount of natural gas that is economically recoverable, which grows with either decreasing costs of producing gas or rising prices paid for gas.

Figure 29: Effect on the Reference Case Natural Gas Marginal Supply Curve of Finding and Development Cost Environment



Source: California Energy Commission staff analysis; Baker Institute. Staff also recalculated marginal production cost curves for the High Gas Demand Case (used in Sensitivity Cases IV, V, and VI.) and for the Low Gas Demand Case (used in Sensitivity Case III). The marginal productions cost curves for all cases are shown in Appendix D, **Figure D-5.**

Appendix D explains how the formation-specific assessments of technically recoverable gas resources are conducted and expressed as probability distributions, using established conventions of the Potential Gas Committee. Staff's Reference Case assumed future F&D costs fall along the midpoint of historical costs, the so-called "Probability 50" or "P50" amount is recoverable—that is, the actual amount is equally likely to be above or below this amount. In constructing this sensitivity, staff could have assumed either a higher or lower (but less likely) quantity is technically recoverable, which would respectively lower or increase resulting model natural gas prices. Staff, however, chose not to make this change for a number of reasons. First, the supply cost curves already include assumptions about future technological innovation. If one believes greater future innovations are likely, then technological recoverable natural gas resources will likely be even higher than the P50 amount. Second, since the assessment is formation-specific, one should expect some plays to come in lower than the P50 amount and others to come in higher, rather than all skewed in one direction or the other. Third, changing this assumption, in addition to others, would result in a range of prices so wide (and improbable) as to be of little use in decision-making. Fourth, the labor-intensity of this particular change to input assumptions ran into timing and resource constraints.

Staff instead chose to make significant changes to the assumptions about the F&D environment that underlie the marginal supply cost curves. The marginal cost profile links the marginal capital cost of production[52] to the quantity of reserves that economic agents can develop. These cost curves represent the capital expenditures needed to expand the natural gas resource base and vary from location to location. These costs depend on two important parameters:

- Current state of knowledge about the resources
- Current level of technology

To develop the cost profile, an analyst must consider all capital expenditure involved in the F&D of natural gas resources. These F&D costs include:

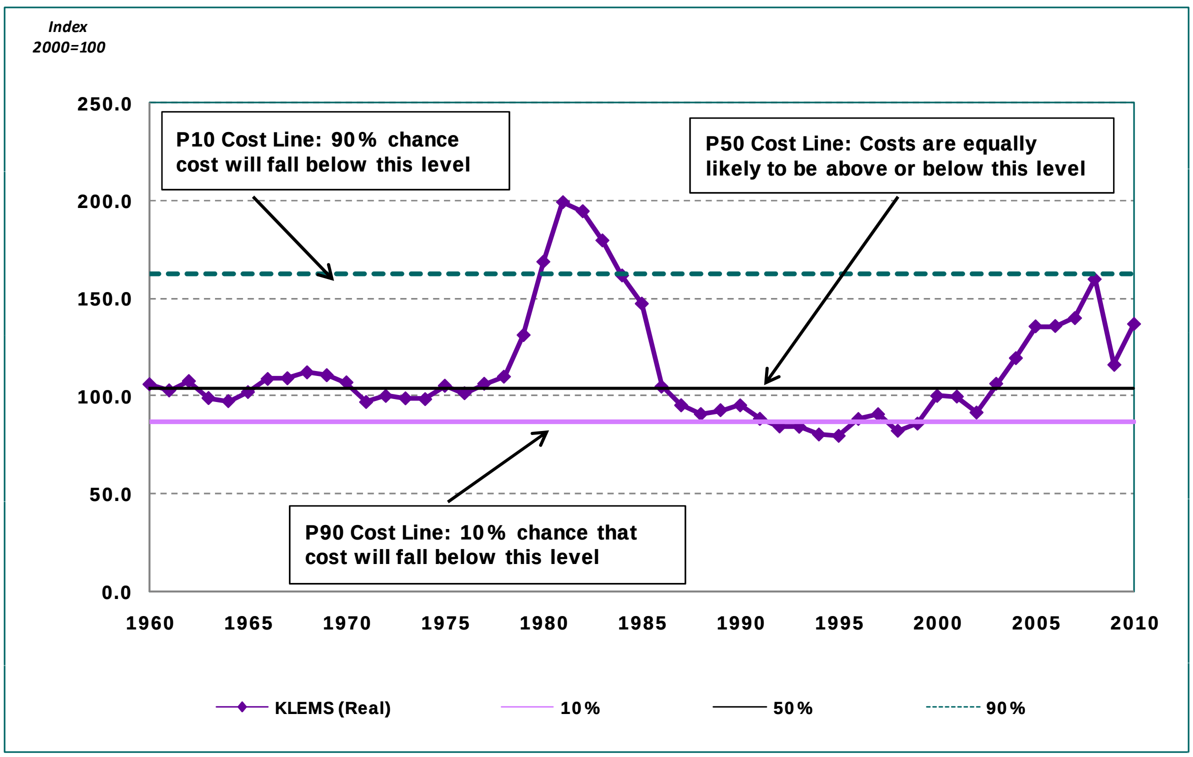
- Surface preparation.
- Exploration cost, including seismic surveys.
- Drilling cost, including setting the casing.[53]
- Completion cost, including hydraulic fracturing if needed.
- Dry hole cost (a proportionate cost added to the development cost to account for the cost of nonproductive wells).

52 The O&M portion of total costs appear elsewhere in the World Gas Trade Model.

53 The string of steel pipe set in drilled hole.

Simulations in a long-term model, such as the WGTM, require a so-called cost environment of production, that is, a year or group of years that typify the cost parameters in the model. **Figure 30,** a schematic of the real cost relationship between 1960 and 2010, shows the indexed KLEMS[54] data for the oil and gas industry. A few examples explain the use of this table. Using 2000 as the base year (assigning it the index value of 100), the 1982 real cost index equals 195, resulting in a 95 percent higher real cost environment in 1982 than in 2000 [(195-100)/100]. Further, since the index in 2010 equaled 137, real costs in 1982 exceeded the 2010 cost environment by about 42 percent [(195-137)/137]. In the Reference Case, staff assumes a cost environment equal to the long-term average of real costs observed between 1960 and 2010. The Reference Case indexed cost value is 103.983 (4 percent greater than in 2000). This long-term average assumption can be termed an "expected" or P50 value—it is equally likely the observed value has been below or above this level.

Figure 30: Indexed Real Cost for the Oil and Gas Industry



Source: Baker Institute.

As mentioned previously, staff's sensitivity cases require deriving alternative assumptions about the future F&D environment that are higher and lower than the P50 level assumed in

54 KLEMS means Capital, Labor, Equipment, Materials, and Services. The Bureau of Economic Analysis produces this data.

the Reference Case. For the High F&D cost environment assumption, staff chose to use a P10 assumption (a very high level that has only been reached or exceeded during 10 percent of the historical record). For the Low F&D cost environment assumption, staff chose to use a P90 assumption (a low level that has been reached or exceeded during 90 percent of the historical record). To derive the P10 and P90 long-term cost environment assumptions for Sensitivity Cases I – IV, staff calculated constant multipliers from the data in **Figure 30**. For example, the multiplier to move from a P50 cost environment to P10 equals 1.567 (162.961/103.983)[55]. **Table 33** displays the constant multipliers for both the P10 and P90 cost environments.

Table 33: Changing the Cost Environment

Cost Environment	Indexed Cost Value	Constant Multiplier for Changing From P50
P10	162.961	1.567
P50	103.983	1.000
P90	87.148	0.838

Source: Baker Institute.

The selection of the cost environment serves as the basis for establishing the link between the marginal cost and reserves additions. **Figure 29** compares the recalculated P10 (High F&D Cost Environment) and P90 (Low F&D Cost Environment) marginal production cost curves with the expected or P50 curves assumed in the current staff Reference Case and the *2007 IEPR* Reference Case.

Finding and Development Cost Environment Assumption Insights and Caveats

The most salient insight to be gained from **Figure 29** is the picture it presents of the dramatic change that has recently occurred in the industry's view about economically recoverable North American natural gas resource base. The dramatic re-assessments of the natural gas resource base arise from several factors:

- High oil and natural gas prices
- Increased levels of F&D activities
- Technological innovations
- Cost reductions through learning improvement

55 The value at the P10 line is 162.961 and 103.983 is the value at the P50 line.

For example, comparing the 2007 and 2011 Reference Case curves (both using P50 assumptions based on then-current knowledge), at $6/MMBtu ($2010) the recoverable resources measure at about 700 Tcf in 2007. Four years later that quantity has increased to about 1,250 Tcf—an almost 80 percent increase. This finding that the economically recoverable resource base is much larger than thought just four years ago is robust over a wide range of assumptions about future F&D capital costs. Even at the unlikely high P10 level of F&D costs, almost 1,100 Tcf is economically recoverable—an almost 60 percent increase since the 2007 resource assessment.

Several other factors tend to confirm this recent change in outlook toward a more abundant North American natural gas resource recoverable at moderate cost. The industry considers the geologic and economic assessments underlying these curves to be "conservative" due to their use in making multibillion dollar investment decisions. Quantities in the assessments tend to increase over time, rather than decrease, as gas field activity brings in more data for the next vintage of assessment. Recent trends not captured in the vintage of data used in this assessment indicate that future F&D costs are more likely to be lower than the P50 assumptions than higher.

Using the P10 and P90 F&D cost environment assumptions in the WGTM means that these conditions of higher-than-average or lower-than-average, respectively, F&D capital costs persist for decades throughout the simulation's future.[56] Conditions like this have never been observed before—real costs tend to cycle back and forth over time with new discoveries and technological innovations. Therefore, these assumptions should be considered very extreme sensitivity tests of potential upper and lower bounds of gas prices, with respect to the F&D costs parameter. For this reason, staff decided not to combine assumptions of low and high resource amounts with assumptions about low and high capital cost environments—the resulting range in prices would be too wide (and improbable) to really be useful.

As generally agreed at the workshop, the assumptions about marginal capital costs of production are key drivers of annual average equilibrium market prices. Other assumptions also affect market price. The following sections discuss two other drivers on which staff based a sensitivity study: the environmental mitigation portion of operations and maintenance costs and the demand for natural gas as a fuel for electric generation.

Rationale for Environmental Mitigation Costs Sensitivity

Of the four sensitivity cases designed to show the effect of the F&D cost environment on equilibrium market prices, Sensitivity Case IV, which starts with the High Gas Price Case and adds a higher-than-average F&D cost environment, would be expected to result in the highest gas prices. Recall from Chapter 2 that the High Gas Price Case already differs from the Reference Case by the following assumptions:

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56 The "learning improvement factor" discussed in Chapter 2 does affect all supply curves over time.

- Remove 50,000 megawatts (MW) of coal-fired generation in the Lower 48—about 280,000 gigawatt-hours (GWh) of annual energy production.[57]
- Robust economic performance, with long-term annual economic growth capped at about 3.5 percent.
- Delay RPS implementation so all states with RPS programs , excluding California, reach their maximum targets 10 years late (extra 5-year delay from the Reference Case's 5-year delay), as states grapple with budgetary concerns and other obstacles, including environmental.
- Robust liquefied natural gas export capability developed and used—Kitimat (Canada, Apache), Sabine Pass (Cheniere), Lake Charles (BG), Freeport, and Cove Point.
- Environmental regulations add $0.40/Mcf to the operations and maintenance cost of developing shale formations and add $0.20/Mcf to conventional resources.
- Remove from development potential shales in particular regions, in particular those in Pennsylvania, New York, Colorado, and Wyoming. This will substantially alter the available gas resource, reestablish a merit order, and alter basis more than price.
- Introduce constraints on natural gas development in Iraq, Iran, Venezuela, and Russia.

The two remaining sensitivity cases are designed to see how much higher gas prices might go than in Sensitivity Case IV if two assumptions already stressed in the High Gas Price Case (and Sensitivity Case IV) were further stressed: the environmental mitigation component of O&M costs and the demand for gas-fueled electricity generation.

Staff assumes additional O&M costs are incurred to encourage, and eventually develop, "best practices" for water handling. The proper handling of water mitigates much of the increased potential environmental impact related to the development of shale resources.[58]

In the High Gas Price Case, environmental regulations add $0.40/Mcf to the O&M cost of developing shale formations and add $0.20/Mcf to conventional resources. These are already imbedded in Sensitivity Case IV. Sensitivity Case V adds an additional $0.30/Mcf to the O&M costs for shale formations, which make them $0.70/Mcf higher in this case than assumed in the Reference Case.

The uncertainties affecting actual future environmental mitigation costs are qualitatively different than the uncertainties surrounding the marginal production cost curves. Lacking a significant long-term historical record of what kind of mitigation may be required or where and at what cost, there are no data on which, or established methods by which, a probability

57 This amount was distributed geographically using findings of an analysis by The Brattle Group of the future viability of existing coal-fired power plants under existing and potentially new air pollutant regulations. See *Potential Coal Plant Retirements Under Emerging Environmental Regulations, Celebi, Graves, Bathla, and Bressan*, The Brattle Group, December 8, 2010, www.brattle.com.

58 See pages 21-22 at http://www.shalegas.energy.gov/resources/081811_90_day_report_final.pdf.

distribution could be developed to build alternative input assumptions. As staff previously discussed in Chapters 1 and 2, this condition characterizes many of the key drivers of the WGTM results, for example, future penetration of nonfossil electric generation. A consequence is that probability cannot be assigned to either results from the original cases discussed in Chapter 3 or new sensitivity cases discussed in this chapter.

Rationale for Additional Coal Retirement Sensitivity

Staff's final sensitivity case, Sensitivity Case VI, adds more stress to the assumptions in Sensitivity Case V. This is the highest stressed case is staff's analysis: adding to the High Gas Price Case increased F&D capital costs, higher environmental mitigation O&M costs, and greater gas demand for electric generation.

PG&E staff commented that about 110 GW of United States coal-fired generating capacity is without emission scrubbers. Given the capital requirements of complying with potential criteria and toxic air emission rules and an enacted CO_2 price, PG&E staff's judgment is that about 80 to 90 GW would convert to natural gas. Staff's High Gas Price Case already assumes 50 GW of coal-to-natural-gas conversion, adding 2.135 trillion cubic feet more generation gas demand than in the Reference Case. Staff's new Sensitivity Case VI assumes a total of 90 GW of coal-fired generation converts to natural gas, adding 3.493 trillion cubic feet more generation gas demand than in the Reference Case.[59] This assumption is at the higher bound of the range of results from the various studies on future coal-fired power plant retirements or conversions staff discusses in Chapter 2.

The studies of coal-fired generation retirements that concluded a high amount of capacity would retire or convert to gas-fired generation also generally made assumptions that tend to push future gas prices lower. So, there is a complex relationship between future coal-fired generating capacity, new gas-fired generating capacity, future gas price, stringency of future environmental regulations disfavoring coal-fired generation, and availability of compliance options other than conversion to gas-fired generation (for example, cost and performance of non-fossil generation or carbon capture and sequestration and/or fixation). Internalizing these complexities is outside of scope of staff's study.

Sensitivity Cases' Natural Gas Price Results

This section discusses the price results from the six sensitivity cases, comparing them to the prices in staff's original cases which were designed to move market price and discussed in Chapter 3. This discussion reports real prices in $2010.[60] Appendix G contains both real and nominal prices for all of the six original cases and the six sensitivity cases, as well as the

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59 These are the econometrically estimated reference quantities of demand that are input into the WGTM, not the model's output final equilibrium demand levels.

60 Recall that the WGTM inputs, computations, and outputs are in real 2005 dollars.

GDP deflator series used to make the conversion. The discussion that follows focuses on prices between 2014 through 2030, for reasons given in the price discussion of Chapter 3—earlier modeled prices are affected either by actual historical data being used as input assumptions or by modeling artifacts.

Price Findings From the Sensitivities on Finding and Development Cost Environment

Table 34 shows the annual average spot market price of natural gas at Henry Hub in $2010/MMBtu for the Reference Case, the High and Low Gas Price Cases, and the four new sensitivities based on these cases, but which alter the assumption about the future F&D cost environment. To aid discussion of the results, **Figure 31** illustrates the same information in **Table 34**. As a convenient way to represent and compare each case's future price series estimates, staff provides two simplifying metrics: the average of annual prices from 2014 to 2022, and the average of annual prices from 2023 to 2030. These metrics also make it convenient to represent percentage differences between the Reference Case and a case of interest.

As they were designed to do, these sensitivity cases widened the range of natural gas price results that previously had been defined by the Low Gas Price and High Gas Price Cases.

Sensitivity Cases I and IV address the question: How was the upper bound of prices changed by increasing the F&D cost environment assumption?

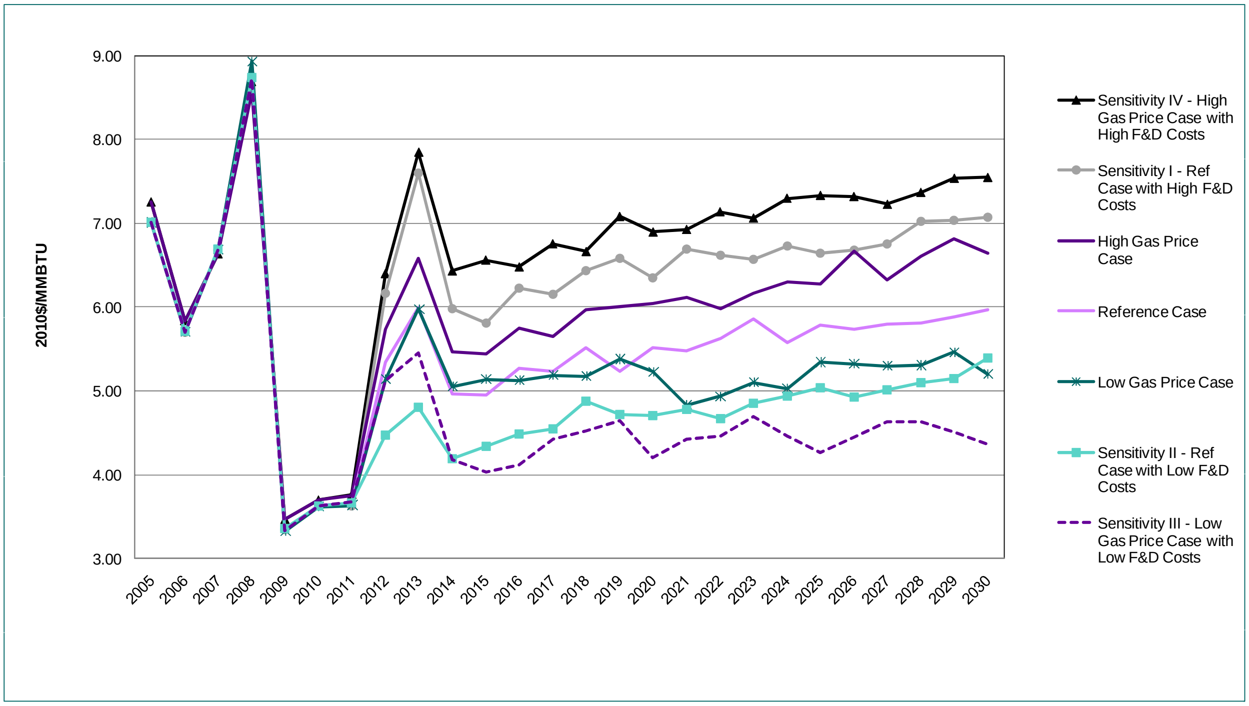
- The High Gas Price Case has prices 9.8 percent higher than the Reference Case's 2014 to 2022 average price and 11.6 percent higher than the 2023 to 2030 average.
- Sensitivity Case I, which adds a high (P10) F&D cost environment assumption to the Reference Case, increases Reference Case average price over 2014 to 2022 by 19.1 percent and over 2023 to 2030 by 17.4 percent.
- Sensitivity Case IV, which adds the high (P10) F&D cost environment assumption to the High Gas Price Case, increases Reference Case average price over 2014 to 2022 by 27.5 percent and over 2023 to 2030 by 26.3 percent.

Table 34: Effect of Finding and Development Cost Environment on Original and Sensitivity Cases Annual Average Spot Market Prices of Natural Gas at Henry Hub, $2010/MMBtu

Year	Sensitivity III -Low Gas Price Case Plus Low F&D Costs	Sensitivity II - Ref Case With Low F&D Costs	Low Gas Price Case	Reference Case	High Gas Price Case	Sensitivity I - Ref Case With High F&D Costs	Sensitivity IV - High Gas Price Case Plus High F&D Costs
2005	7.01	7.01	7.01	7.01	7.25	7.01	7.25
2006	5.70	5.70	5.70	5.70	5.83	5.70	5.83
2007	6.68	6.68	6.68	6.68	6.63	6.68	6.63
2008	8.72	8.74	8.93	8.90	8.56	8.75	8.68
2009	3.34	3.36	3.33	3.33	3.47	3.35	3.47
2010	3.64	3.63	3.62	3.63	3.70	3.63	3.69
2011	3.68	3.66	3.64	3.65	3.75	3.64	3.76
2012	5.12	4.47	5.14	5.34	5.74	6.17	6.40
2013	5.46	4.80	5.98	5.99	6.58	7.61	7.84
2014	4.18	4.18	5.05	4.96	5.47	5.98	6.43
2015	4.04	4.34	5.14	4.95	5.44	5.81	6.56
2016	4.12	4.48	5.13	5.27	5.74	6.23	6.47
2017	4.42	4.54	5.19	5.23	5.65	6.16	6.75
2018	4.53	4.88	5.18	5.51	5.97	6.43	6.66
2019	4.65	4.72	5.38	5.23	6.01	6.59	7.08
2020	4.20	4.71	5.23	5.51	6.04	6.36	6.89
2021	4.43	4.78	4.83	5.47	6.12	6.69	6.92
2022	4.47	4.67	4.94	5.63	5.98	6.62	7.13
2023	4.70	4.85	5.11	5.86	6.17	6.57	7.06
2024	4.47	4.94	5.03	5.58	6.30	6.72	7.29
2025	4.28	5.03	5.34	5.79	6.28	6.65	7.33
2026	4.46	4.93	5.32	5.74	6.66	6.68	7.31
2027	4.64	5.01	5.30	5.80	6.33	6.75	7.22
2028	4.63	5.09	5.31	5.80	6.60	7.03	7.36
2029	4.51	5.14	5.46	5.88	6.81	7.04	7.53
2030	4.37	5.38	5.20	5.97	6.65	7.07	7.54
Avg 2014-22	4.34	4.59	5.12	5.31	5.82	6.32	6.77
Avg 2023-30	4.51	5.05	5.26	5.80	6.47	6.82	7.33
2014-22	-18.2%	-13.5%	-3.5%	**% Avg < or >**	9.8%	19.1%	27.5%
2023-30	-22.4%	-13.0%	-9.4%	**Ref Case**	11.6%	17.4%	26.3%

Source: California Energy Commission staff analysis.

Figure 31: Effect of Finding and Development Cost Environment on Original and Sensitivity Cases' Annual Average Spot Market Prices of Natural Gas at Henry Hub, $2010/MMBtu



Source: California Energy Commission staff analysis.

While the high F&D cost environment assumption in these two sensitivity cases does move prices significantly upward, these price outcomes are less likely to occur for the reasons previously discussed—the high F&D cost conditions are less likely to occur than the expected conditions assumed in the Reference Case and the High Gas Price Case, especially sustained over the length of the simulation period.

Sensitivity Cases II and III address the question: How was the lower bound of prices changed by decreasing the F&D cost environment assumption?

- The Low Gas Price Case has prices 3.5 percent lower than the Reference Case's 2014 to 2022 average price and 9.4 percent lower than the 2023 to 2030 average.
- Sensitivity Case II, which adds a low (P90) F&D cost environment assumption to the Reference Case, decreases Reference Case average price over 2014 to 2022 by 13.5 percent and over 2023 to 2030 by 13 percent.
- Sensitivity Case III, which adds the low (P90) F&D cost environment assumption to the Low Gas Price Case, decreases Reference Case average price over 2014 to 2022 by 18.2 percent and over 2023 to 2030 by 22.4 percent.

While the low F&D cost environment assumption in these sensitivity cases does move prices significantly downward, these price outcomes are less likely to actually occur, for the reasons previously discussed—the low F&D cost conditions are less likely to occur than the P50 conditions assumed in the Reference Case and the Low Gas Price Case, especially sustained over the length of the simulation period.

Price Findings From the Sensitivities on Environmental Mitigation Costs and Coal-Fired Generation Capacity Retirements

Table 35 shows the annual average expected spot market price of natural gas at Henry Hub in $2010/MMBtu for the Reference Case and Sensitivity Cases IV, V and VI. **Figure 32** illustrates the same information in **Table 35**. As a convenient way to represent and compare each case's future price series estimates, staff provides two simplifying metrics: the average of annual prices from 2014 to 2022, and the average of annual prices from 2023 to 2030. These metrics also make it convenient to represent percentage differences among cases.

Sensitivities V and VI address the question: How much higher than Sensitivity Case IV prices can additional environmental mitigation costs and coal-fired generating capacity retirements drive gas prices?

- Sensitivity Case IV is the highest priced F&D cost environment sensitivity case, having added the high (P10) F&D cost environment assumption to the High Gas Price Case, increasing Reference Case average price over 2014 to 2022 by 27.5 percent and over 2023 to 2030 by 26.3 percent.
- Sensitivity Case V adds a $0.30/Mcf increment to the $0.40/Mcf additional environmental mitigation cost portion of O&M costs of shale development already embedded in the High Gas Price Cases and Sensitivity Case IV, making this assumption $0.70/Mcf higher than in the Reference Case.
  - Incrementally increasing average price over 2014 to 2022 from Sensitivity Case IV values by 2.6 percent and over 2023 to 2030 by 2.4 percent.
  - Compared to the Reference Case, Sensitivity Case V average price over 2014 to 2022 is 30.8 percent higher and over 2023 to 2030 is 29.3 percent higher.
- Sensitivity Case VI adds an increment of 40 GW of coal-fired generating capacity retirements to the 50 GW already embedded in the High Gas Price Case and Sensitivity Case IV (and V), making the difference from the Reference Case 90 GW.
  - Incrementally changing Sensitivity Case VI average price over 2014 to 2022 by only a 0.4 percent increase and over 2023 to 2030 by a 0.4 percent decrease. Unexpectedly, this incremental change has little effect on prices.
  - Compared to the Reference Case, Sensitivity Case VI average price over 2014 to 2022 is 31.3 percent higher and over 2023 to 2030 is 28.8 percent higher.

Unlike the changes staff made about the future F&D cost environment in Sensitivity Cases I–IV, staff has no historical record or method by which to assign a probability distribution to the range of values future environmental mitigation costs or coal-fired capacity retirements could take.

Table 36 shows a summary and differences across sensitivity cases. Focusing on California's natural gas uses for power generation, staff "post-processed" (four selected output metrics), from 2017, 2022, and 2030 model results for sensitivity cases. These include annual generation gas demand, fuel cost, combustion-related carbon (CO_2) emissions, and potential emission allowance costs.

Table 35: Effect of Additional Environmental Mitigation Costs and Coal Generating Capacity Retirements on Reference and Sensitivity Cases' Annual Average Spot Market Prices of Natural Gas at Henry Hub, $2010/MMBtu

Year	Reference Case (P50 F&D Costs Assumed)	Sensitivity IV - High Gas Price Case With High F&D Costs	Sensitivity V - Sens IV With Additional $0.30/McfRef O&M	Sensitivity VI - Sens V With Additional 40 GW Coal Conversion
2005	7.01	7.25	7.32	7.32
2006	5.70	5.83	5.94	5.94
2007	6.68	6.63	6.78	6.78
2008	8.90	8.68	8.53	8.60
2009	3.33	3.47	3.59	3.58
2010	3.63	3.69	3.86	3.86
2011	3.65	3.76	3.92	3.91
2012	5.34	6.40	6.22	6.15
2013	5.99	7.84	7.92	8.05
2014	4.96	6.43	6.86	6.73
2015	4.95	6.56	6.33	6.64
2016	5.27	6.47	6.84	6.89
2017	5.23	6.75	6.71	6.79
2018	5.51	6.66	7.06	6.89
2019	5.23	7.08	7.04	7.23
2020	5.51	6.89	7.03	6.98
2021	5.47	6.92	7.37	7.40
2022	5.63	7.13	7.21	7.13
2023	5.86	7.06	7.39	7.37
2024	5.58	7.29	7.35	7.31
2025	5.79	7.33	7.22	7.22
2026	5.74	7.31	7.66	7.32
2027	5.80	7.22	7.40	7.30
2028	5.80	7.36	7.76	7.70
2029	5.88	7.53	7.63	7.90
2030	5.97	7.54	7.63	7.67
Avg 2014-2022	5.31	6.77	6.94	6.97
Avg 2023-2030	5.80	7.33	7.51	7.48
2014-2022	**% Avg >**	27.5%	30.8%	31.3%
2023-2030	**Ref Case**	26.3%	29.3%	28.8%
2014-2022		**% Avg >**	2.6%	3.0%
2023-2030		**Case IV**	2.4%	2.0%
2014-2022			**% Avg < or >**	0.4%
2023-2030			**Case V**	-0.4%

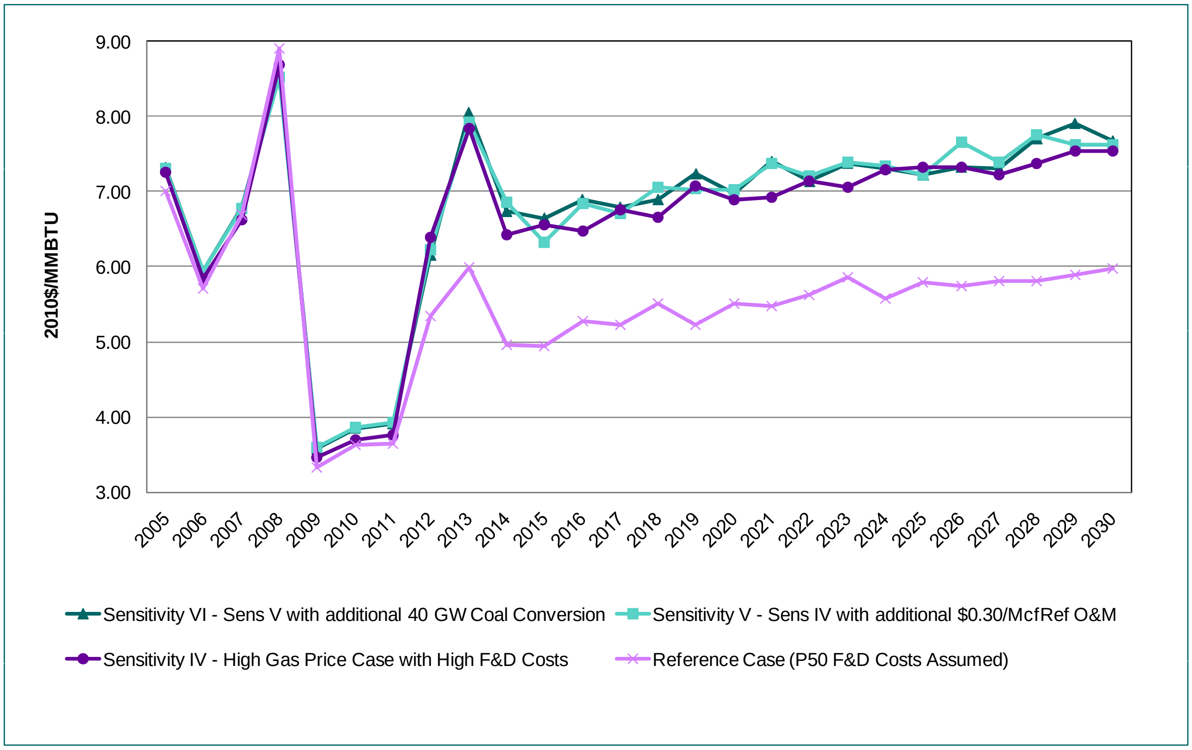
Source: California Energy Commission staff analysis.

Table 36: Estimates of California Power Generation Sector Gas Demand, Gas Costs, Combustion CO_2 Emissions, and Minimum CO_2 Allowance Costs by Sensitivity Case

Selected California Power Generation Sector Results	Reference	Sensitivity Case I	Sensitivity Case II	Sensitivity Case III	Sensitivity Case IV	Sensitivity Case V	Sensitivity Case VI
2017							
Gas Demand (Bcf/Yr)	696.6	648.3	747.7	747.2	640.7	631.2	627.6
Combustion CO_2e Emissions (Millions Tonnes CO_2/yr)	38.5	35.9	41.4	41.3	35.4	34.9	34.7
Gas Costs (Millions $2010/yr)	$4,285.5	$3,988.4	$4,922.0	$4,619.7	$4,138.7	$3,941.6	$3,854.6
CO_2e Allowance Costs (Millions $2010/yr)	$465.2	$432.9	$499.3	$488.0	$427.8	$421.5	$419.1
2022							
Gas Demand (Bcf/yr)	650.7	583.8	711.8	726.3	600.3	589.5	585.9
Combustion CO_2e Emissions (Millions Tonnes CO_2/yr)	36.0	32.3	39.4	40.2	33.2	32.6	32.4
Gas Costs (Millions $2010/yr)	$4,310.1	$3,867.2	$4,934.5	$4,326.3	$4,204.8	$3,826.3	$3,923.4
CO_2e Allowance Costs (Millions $2010/yr)	$555.1	$498.1	$607.3	$619.6	$512.2	$502.9	$499.9
2030							
Gas Demand (Bcf/yr)	658.6	582.0	730.1	771.8	624.1	610.1	606.3
Combustion CO_2e Emissions (Millions Tonnes CO_2/yr)	36.4	32.2	40.4	42.7	34.5	33.8	33.5
Gas Costs (Millions $2010/yr)	$4,619.7	$4,082.1	$5,638.8	$4,692.2	$4,614.8	$4,135.6	$4,190.5
CO_2e Allowance Costs (Millions $2010/yr)	$829.3	$732.8	$919.4	$971.8	$785.9	$768.3	$763.5

Source: California Energy Commission staff analysis. These are estimates.

Figure 32: Effect of Additional Environmental Mitigation Costs and Coal Generating Capacity Retirements on Reference and Sensitivity Cases' Annual Average Spot Market Prices of Natural Gas at Henry Hub, $2010/MMBtu



Source: California Energy Commission staff analysis.

General Caveats on Price Results

The WGTM price results represent the annual average of what prices would have to be for the investment decisions made by the model to be economically feasible over the long-term. In this assessment, staff has varied assumptions about the future values of independent variables, focusing attention on those generally accepted to be key drivers of gas prices and demand over the long term.

Since staff did not vary input assumptions that can be drivers of prices and demand in the short term, the WGTM results do not reflect the effects of such regular seasonal or occasional expected or unexpected variations. Some examples include:

- Seasonal and year-to-year variations in cooling and heating degree days, which affect gas demand.
- Unusual severe weather events such as hurricanes or widespread freezing temperatures that may disrupt gas production, transportation, or demand.
- Annual variations in hydroelectric generation.

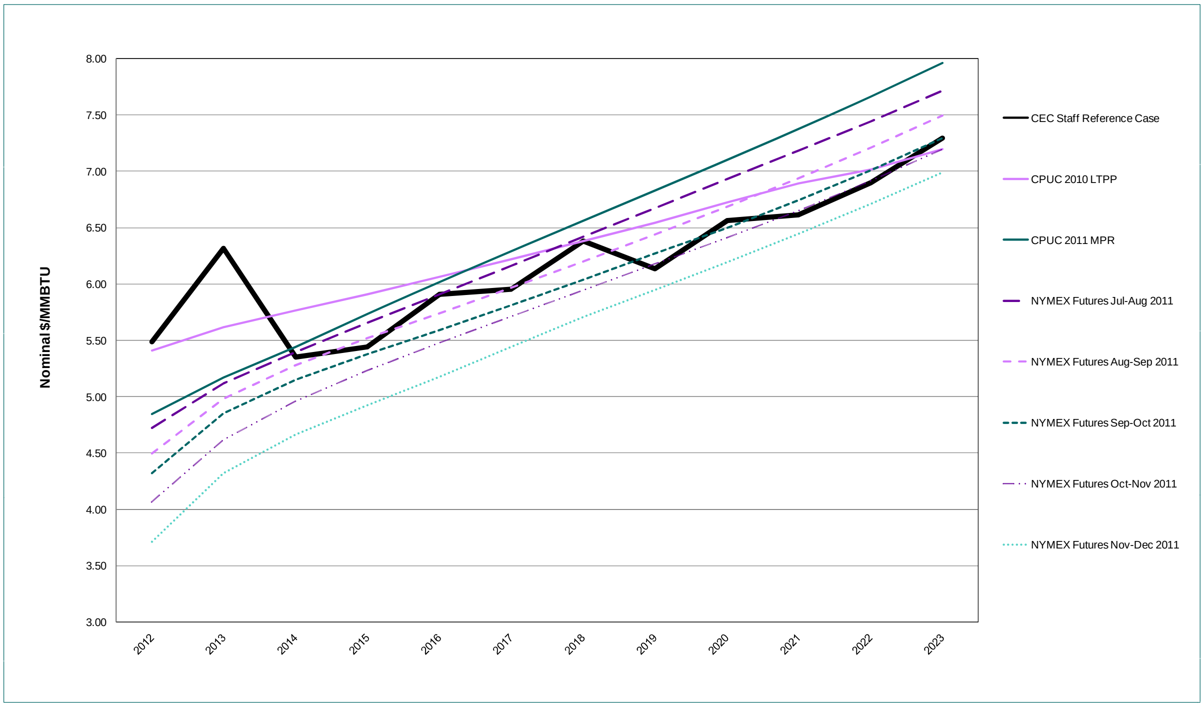
Staff's focus in this assessment has been on wholesale market activities and commodity costs. Although Chapter 4 discusses retail gas prices, and staff has posted retail prices associated with the original WGTM cases to the Energy Commission's website, this assessment has not comprehensively explored the range of future transportation costs that make up more than half of residential rates. Chapter 4 points out potentially significant sources of uncertainty about future transportation rate components: pipeline integrity inspection and replacement costs, AB 32 cap-and-trade emission allowance costs, public purpose program charges, and other potential environmental costs.

New York Mercantile Exchange Spot Market Futures Prices

Chapter 3 has a brief discussion of futures-based natural gas price forecasts, which have been used over the past decade in various California energy regulatory mechanisms (see **Figure 5**). The most recent futures-based forecast discussed in that section is the one that the CPUC directed be used in the 2010 LTPP. Since then, the CPUC has directed the 2011 MPR be calculated for the small renewable generator feed-in tariff program. These two gas price forecasts are shown in **Figure 33,** together with staff's Reference Case WGTM price results. To get a sense of even more recent movements in spot prices over time, staff also added five dotted lines that successively apply the same CPUC-directed method for using futures strips as gas price forecasts, but to more current vintages of posted daily futures prices. These five gas futures price strips average daily closing Henry Hub prices over 22 consecutive trading days beginning about the 9th day of the 1st month through about the 11th of the following month.

Given staff's explanation of the WGTM pre-2014 price results in Chapter 3, some other source of estimates of near-term gas prices could fill this information gap. NYMEX futures strips are readily available and are already accepted in various California energy regulatory mechanisms. Since the volume of trades on which NYMEX prices are based is higher in the first few years of the strips, these years can be a useful source of near-term price estimates. A disadvantage is that the estimates do not come with an explicit list of future conditions and assumptions on which the market participants are basing their investment decisions. For example, some agencies make purchases of gas to be delivered in the future based on what the agency has as a budget for energy purchases. Although the agencies are concerned about the price of natural gas, they are more concerned on exceeding their allocated budget. These factors are difficult to foresee when evaluating whether the futures market would be a good predictor of natural gas prices.

Figure 33: Staff Reference Case Price Results Compared to Recent Futures-Based Annual Average Henry Hub Natural Gas Spot Purchase Prices



Source: Reference Case - (Energy Commission staff analysis); CPUC 2010 LTPP- (E3: Energy + Environmental Economics, April 2011 Evaluation Metric Calculator at http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/LTPP2010/LTPP_System_Plans.htm); CPUC 2011 MPR - (http://www.cpuc.ca.gov/NR/rdonlyres/CD8EC93F-F34E-484A-8804-594D79A654B2/0/DRAFT2011MPRModel.xls); NYMEX Futures - (http://intelligencepress.com/).

Others' Price Forecasts

Staff has included recent natural gas price forecasts from a variety of sources in Appendix E and compared them to the WGTM results for the annual average equilibrium price of natural gas at Henry Hub. The results of staff's sensitivity cases were not available in time to include in these comparisons. Because the details of assumptions and methods underlying many of the other forecasts are not well described or fully documented, extensive point-to-point comparisons to staff's assumptions and methods are not feasible to make.

List of Acronyms

Acronym	Proper Name
AB 32	Assembly Bill 32
AB 723	Assembly Bill 723
AEO 2010	*2010 Annual Energy Outlook*
API	American Petroleum Institute
BCAP	Biennial Cost Allocation Proceeding
Bcf, Bcf/d	Billion cubic feet, billion cubic feet per day
CARE	California Alternate Rates for Energy
CO_2	Carbon dioxide
CPUC	California Public Utilities Commission
DSM	Demand-side management
Dth	Decatherm
EIA	Energy Information Administration
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency
EPNG	El Paso Natural Gas
EUR	Estimated ultimate recovery
F&D	Finding and development
GDP	Gross domestic product
GHG	Greenhouse gas
GTN	TransCanada Gas Transmission Northwest
GWh	Gigawatt-hours
HCAs	High Consequence Areas
ICE	Intercontinental Exchange
IEA	International Energy Agency
IECA	Industrial Energy Consumers of America
IEPR	*Integrated Energy Policy Report*
INGAA	Interstate Natural Gas Association
KLEMS	Capital, Labor, Equipment, Materials, and Services
LTPP	Long-Term Procurement Proceeding
LNG	Liquefied natural gas
MAOP	Maximum Allowable Operating Pressure
Mcf	Thousands of cubic feet

Acronym	Proper Name
Mcfe	Thousand cubic feet equivalent
MIT	Massachusetts Institute of Technology
MMBtu	Million British thermal units
MMcf/d	Million cubic feet per day
$MMTCO_{2E}$	Million metric tons carbon dioxide equivalent
MPR	Market Price Referent
MW	Megawatts
N_2O	Nitrous oxide
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Council
NO_x	Nitrogen oxide
NTSB	National Transportation Safety Board
NWPCC	Northwest Power and Conservation Council
NYMEX	New York Mercantile Exchange
O&M	Operation & Maintenance
OCS	Outer Continental Shelf
OECD	Organization for Economic Co-operation and Development
OFO	Operational flow order
OIR	Order Instituting Rulemaking
PCB	Polychlorinated biphenyl
PG&E	Pacific Gas and Electric
PGC	Potential Gas Committee
PHMSA	Pipeline and Hazardous Material Safety Administration
PPP	Public Purpose Program
REX	Rocky Mountain Express Pipeline
RFO	Residual fuel oil
RPS	Renewables Portfolio Standard
RWGTM	Rice World Gas Trade Model
SAP	Scenario Analysis Project
SDG&E	San Diego Gas & Electric
SO_2	Sulphur dioxide
SoCalGas	Southern California Gas Company
STEO	*Short-Term Energy Outlook*
Tcf	Trillion cubic feet

Acronym	Proper Name
Tcf/yr	Trillion cubic feet per year
TEOR	Thermal enhanced oil recovery
Thm	Therm
TSCA	Toxic Substances Control Act
U.K. NBP	United Kingdom National Balancing Point
U.S.	United States
U.S. DOE	U.S. Department of Energy
U.S. DOT	U.S. Department of Transportation
U.S. EPA	U.S. Environmental Protection Agency
USD	U.S. dollar
USEIA	U.S. Energy Information Administration
USGS	U.S. Geological Survey
WECC	Western Electricity Coordinating Council
WEO	World Energy Outlook
WGTM	World Gas Trade Model
WPD	Winter peak day
WSGR	Worldwide Shale Gas Resources
WTI	West Texas Intermediate

APPENDIX A:
Glossary of Terms

Absorbed Gas: Methane molecules attached to organic material contained within solid matter.

Backbone Transmission System: The system used to transport gas from a utility's interconnection with interstate pipelines, other local distribution companies, and the California gas fields to a utility's local transmission and distribution system.

Border Price: This is a price at the border of a state; it represents the place where gas goes from an interstate pipeline to an intrastate pipelines. The border location is not always exactly on the border of a state, but is normally very close to it.

Carbon Footprint: The total set of GHG emissions caused directly and indirectly by an individual, organization, event, or product.

Casing: Pipe set with cement in the hole in the earth.

Combined Cycle Gas Turbine: An assembly of engines that convert heat into mechanical energy, which in turn drives electrical generators. The principle is that the exhaust of one heat engine is used as the heat source for another, increasing the system's overall efficiency.

Citygate Price: The price paid by a natural gas utility when it receives natural gas from a transmission pipeline. "Citygate" is used because the transmission pipeline often connects to the distribution system that supplies a city.

Coal-Bed Methane (CBM): Natural gas extracted from coal deposits.

Drilling: The process of boring a hole in the earth to find and remove subsurface fluids such as, oil and natural gas.

Environmental Impact: Adverse effect upon natural ambient conditions.

Formation: A bed or rock deposit composed, in whole, of substantially the same kind of rock; also called reservoir or pool.

Futures Market (natural gas): A trade center for quoting natural gas prices on contracts for the delivery of a specified quantity of a natural gas at a specified time and place in the future. Natural gas futures start from the next calendar month and can go up through 36 months into the future. For example, on October 2, 1998, trading occurs in all months from November 1998 through October 2001.

Groundwater: Water in the earth's subsurface used for human activities, including drinking.

Henry Hub: Located in Southern Louisiana, is a key natural gas pricing point in the Lower 48.

Horizontal Well: A hole at first drilled vertically and then horizontally for a significant distance (500 feet or more).

Hydraulic Fracturing: The forcing into a formation of a proppant-laden liquid under high pressure to crack open the formation, thus creating passages for oil and natural gas to flow through and into the wellbore. Also known as "fracking" or "fraking."

Local Transmission System: The term "local transmission system" includes the pipeline used to accept gas from the backbone transmission system and transport it to the distribution system.
Manipulation: Any planned operation, transaction, or practice that causes or maintains an "artificial price." The Commodities Futures Trade Commission defines artificial price as a price higher or lower than it would have been if it reflected the forces of supply and demand.
Net Present Value: The process of finding the current-date value of a stream of future periodic cash-flows. Present value of revenues minus present value of costs gives the net present value.
New York Mercantile Exchange (NYMEX): The world's largest physical commodity futures exchange. Trading is conducted through two divisions: the NYMEX Division, which is home to the energy, platinum, and palladium markets, and the Commodity Exchange Division, where metals like gold, silver, and copper and the FTSE 100 index options are traded. The NYMEX uses an outcry trading system during the day and an electronic trading system after hours.
Original Gas-in-Place: The total initial volume (both recoverable and nonrecoverable) of oil and/or natural gas in-place in a rock formation.
Permeability: The ability of a fluid (such as oil or natural gas) to flow within the interconnected pore network of a porous medium (such as a rock formation).
Porosity: The condition of a rock formation by which it contains many pores that can store hydrocarbons.
Production Decline Profile: A chart demonstrating the depletion of a producing well.
Proppant: A granular substance (sand grains, walnut shells, or other material) carried in suspension by a fracturing fluid that keep the cracks in the shale formation open after the well operator retrieves the fracturing fluid.
Recoverable Reserves: The unproduced but recoverable oil and/or natural gas in-place in a formation.
Rig Count: The number of drilling rigs actively punching holes in the earth.
Shale: A fine-grained sedimentary rock whose original constituents were clay minerals or mud.
Shale Gas: Natural gas produced from shale formations.
Shale play: A geographic area containing an organic-rich fine-grained sedimentary rock with the following characteristics: Particles are the size of clay or silt, contains a high percentage of silica (and sometimes carbonates), is thermally mature, has hydrocarbon-filled porosity and low permeability, is distributed over a large area, and economic production requires fracture stimulation.
Spot Market (natural gas): A market in which natural gas is bought and sold for immediate or very near-term delivery, usually for a period of 30 days or less. The transaction does not imply a continuing agreement between the buyers. A spot market is more likely to develop at a location with numerous pipeline interconnects, thus allowing for a large number of buyers and sellers. The Henry Hub in Southern Louisiana is the best known spot market for natural gas.

Spot Price (natural gas): The price for a one-time open market transaction for near-term delivery for a specific quantity of natural gas at a specific location where the natural gas is purchased at current market rates.
Stimulation: The process of using methods and practices to make a well more productive.
Tight Gas: Natural gas from very low permeability rock formations.
Unconventional Production: Natural gas from tight formations or from coal deposits or from shale formations.
Well Completion: The activities and methods necessary to prepare a well for the production of oil and natural gas.
Well: A hole in the earth caused by the process of drilling.
Wellbore: The hole made by drilling for exploration and production of resources. It may be cased, for example, pipe set by cement within the hole.
Wellhead Price: The value at the mouth of the gas well. In general, the wellhead price is considered to be the sales price obtainable from a third party in an arm's length transaction. (No transportation or processing costs are included.) Posted prices, requested prices, or prices as defined by lease agreements, contracts, or tax regulations should be used where applicable.

APPENDIX B:
Development of the Reference Case From the Rice World Gas Trade Model

This appendix is Dr. Ken Medlock's Microsoft PowerPoint® presentation saved as an Adobe PDF® file. The PDF file is posted on the Energy Commission website at this link:

http://www.energy.ca.gov/2011_energypolicy/documents/2011-09-27_workshop/Appendix_B/

APPENDIX C:
Guide to World Gas Trade Model Results for All Study Cases

This appendix is a guide to the structure of the Microsoft Excel files that contain the WGTM results for each of the study cases: Reference, High United States Gas Price, Low United States Gas Price, Constrained Shale Gas, High CA Gas Demand, Low CA Gas Demand, Lowered Pressure cases, and the six sensitivities conducted after the September 27, 2011, workshop. **Table C-1** explains the nomenclature used in the model result files. Each of the Excel files contains results from a particular case, each divided into 19 sheets, and each presenting a different aspect of the model output. Two versions of the Excel worksheets—.xls and .xlsx—are provided. The files are posted at:
http://www.energy.ca.gov/2011_energypolicy/documents/2011-09-27_workshop/xls_results/

Table C-1: Explanation of Nomenclature in Model Results

Spreadsheet Tab Name	Explanation of Sheet	Sample Name Within Sheet	Remarks
CHARTS	This sheet contains two graphs: U.S. Demand Totals and California Demand Total.		Graphs contain no names that required further explanation.
U.S._Dmd_Total	This sheet contains actual historical data and the model results for U.S. Natural Gas Demand.	Sheet lists natural gas demand by state.	
Calif_Dmd_Total	This sheet contains actual historical data and the model results for California Natural Gas Demand.	**D: U.S.-CA PG&E (Ind):** This name conveys that this demand is in the United States, in California, and in PG&E's service territory. Further, the information represents the industrial demand in the specified jurisdiction.	All represented demands in the WGTM begin with D: • Res represents residential • Comm represents Commercial • Ind represents Industrial • Pwr represents Power Generation.
Calif_Dmd_PGE	This sheet contains actual historical data and the model results for Natural Gas Demand the Pacific Gas and Electric service territory.	Similar to the above.	
Calif_Dmd_SoCal	This sheet contains actual historical data and the model results for Natural Gas Demand the SoCal service territory.	Similar to the above with the information now tailored to the SoCal service territory.	

Spreadsheet Tab Name	Explanation of Sheet	Sample Name Within Sheet	Remarks
Calif_Dmd_SDGE	This sheet contains actual historical data and the model results for Natural Gas Demand the San Diego Gas & Electric service territory.	Similar to the above with the information now tailored to the San Diego Gas & Electric service territory.	
US_Dmd_PGen	This sheet contains actual historical data and the model results for U.S. Power Generation Natural Gas Demand.	**D: US-PA Pittsburgh (Pwr):** This name conveys that this demand is in the United States, in Pittsburgh, Pennsylvania. Further, the information represents the Power Generation demand in the specified jurisdiction. **(1)**	
WECC(US-CAN)_Dmd_PGen	This sheet contains actual historical data and the model results for Western Energy Coordinating Council for U.S. and Canada Natural Gas Demand.	Similar to the above with the information now tailored to the WECC states in both Canada and the United States.	Only whole states in the United States represented in the totals.
WECC(US)_Dmd_PGen	This sheet contains actual historical data and the model results for Western Energy Coordinating Council for U.S. Natural Gas Demand.	Similar to the above with the information now tailored to the WECC states in the United States.	Only whole states in the United States represented in the totals.
US_Prod_Total	This sheet contains actual historical data and the model results for U.S. Natural Gas Production.	Sheet lists natural gas production by state.	

Spreadsheet Tab Name	Explanation of Sheet	Sample Name Within Sheet	Remarks
US_Prod_Shale	This sheet contains actual historical data and the model results for U.S. Shale Natural Gas Production.	**S: US-Gulf Coast-Texas RRC 4 (Eagle Ford T1) Shale YTF:** This name conveys that this supply resource is in the United States, in the Gulf Coast, in Texas Railroad Commission District 4, and in the Eagle Ford producing basin. Further, the information represents production from a shale formation. YTF stands for Yet To Find, which means that this supply resource is a potential resource.	All represented supply resources in the WGTM begin with S: GTK means Growth to Known. This represents the reserve appreciation.
Calif_Prod_Total	This sheet contains actual historical data and the model results for California Natural Gas Production.	Similar to the above with the information now tailored to California. **(2)**	
Calif_Supply_Total	This sheet contains model results for California Natural Gas Supply and Demand.	**P: US-Kern (UT to CA):** This name conveys that this pipeline is in the United States, and is named Kern (River), with this leg travelling from Utah to California.	All represented pipelines or pipeline corridors in the WGTM begin with P:
Can_Prod_Total	This sheet contains actual historical data and the model results for Canada Natural Gas Production.	Similar to (2) above with the information now tailored to Canada.	

Spreadsheet Tab Name	Explanation of Sheet	Sample Name Within Sheet	Remarks
Can_Imports	This sheet contains actual historical data and the model results for US imports of Natural Gas from Canada.	**Hub: Canada-British Columbia-Sumas:** This name conveys that this hub is in Canada, in British Columbia, and is located at Sumas.	Hubs represent locations into which pipelines are connected and out of which natural gas flows, also along pipelines.
LNG_Imports	This sheet contains actual historical data and the model results for U.S. imports of Liquefied Natural Gas.	**Proc: LNG Regas-US (Cove Point) (Contract):** This name conveys that this LNG re-gasification processing facility is located in the United States and at Cove Point. Further, this represents the contracted flows.	**Proc:** Can represent a LNG regasification facility or a liquefaction facility or a wellhead processing facility.
CA_Dmd_PGen	This sheet contains actual historical data and the model results for California Natural Gas Demand for Power Generation.	Similar to (1) above with the information now tailored to California.	
Calif_RefDmd	This sheet contains model input reference demands for Power Generation and other sectors in California.	Similar to above	
HubPrices	This sheet contains Natural Gas prices for selected pricing hubs in the United States	**Hub: US-Malin:** This name conveys that this hub is in the United States and located at Malin, Oregon.	

Source: Energy Commission staff analysis

APPENDIX D: Estimating Natural Gas Reserves and Marginal Production Costs

In the WGTM, two of the most significant drivers of the long-term price and supply outcomes are the assumed estimates of the quantity of natural gas reserves and the marginal cost of producing the gas. This appendix describes how these assumptions are developed.

Reserves Estimates

The estimates of natural gas reserves fall into various categories, with each category signaling a level of certainty. The inexact science of estimating natural gas reserves generates many difficulties in understanding the nature and quantity located in subsurface reservoirs[61]. As such, reserve estimates measure geologic risk, that is, the probability that volumes of natural gas exist in earth's subsurface and that the industry, using current technology in the current economic climate, can produce this fossil fuel. The emergence of technological innovations has eased some of the uncertainty. However, the classification of natural gas reserves correlates with the probability of eventual production and industry observers place reserves into the following four classifications:

- **Proven reserves:** The Potential Gas Committee (PGC)[62] views this category as *"the quantities of natural gas that current analysis of geologic and engineering data demonstrate with reasonable certainty to be recoverable in the future from known … gas reservoirs under existing economic and operating conditions."* The probability of actual production of these resources equals or exceeds 90 percent. As a result, industry observers label this estimate as P90.
- **Probable reserves**: The PGC views this category as those *"… resources [that] are associated with known fields and are the most assured of potential supplies. Relatively large amounts of geologic and engineering information are available to aid in the estimation of resources existing in this category."* The probability of actual production of these resources equals or exceeds 50 percent.
- **Possible reserves**: The PGC views this category as those *"… resources that are a less assured supply because they are postulated to exist outside known fields, but they are associated with a productive formation in a productive [region]. Their occurrence is indicated by a*

61 Also called pools or formations.

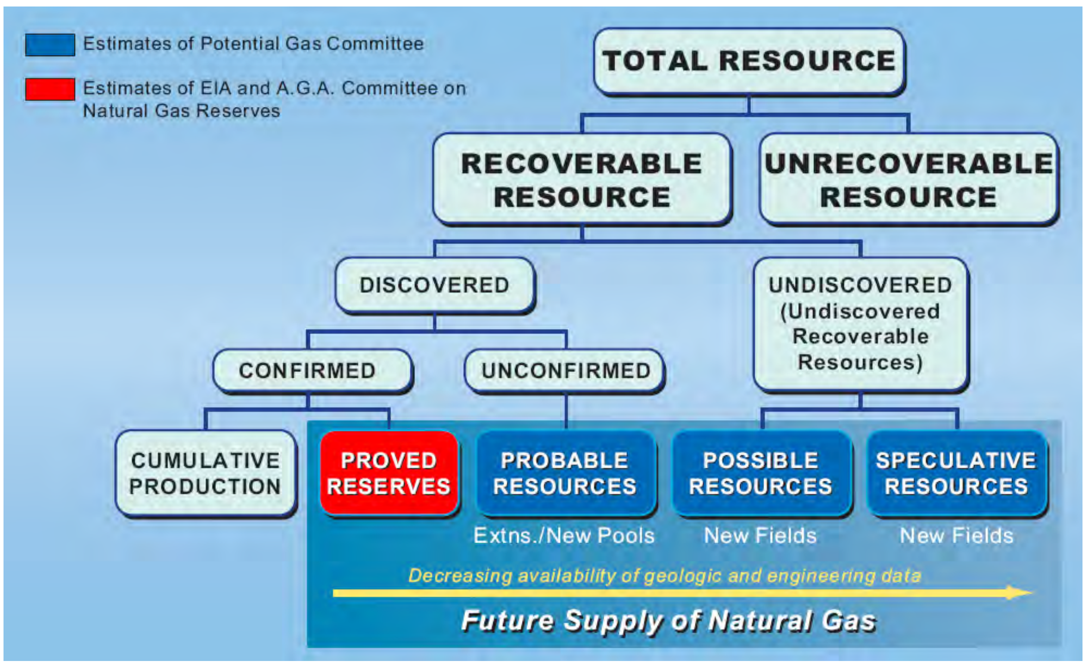
62 Exact classifications may vary with the source of the data.

projection of plays or trends of a producing formation into a less well explored area of the same geologic [era]." The probability of actual production of these resources equals or exceeds 10 percent.

- **Speculative reserves:** The PGC views this category as those *"… resources [that] are expected to be found in formations or geologic provinces that have not yet proven productive."* The probability of actual production of these resources falls below 10 percent.

Figure D-1 demonstrates the reserve categories. The WGTM uses two categories of reserves: proven and potential (probable and possible).

Figure D-1: Reserve Categories From the Potential Gas Committee



Source: Potential Gas Committee

However, the inexact nature of reserve estimation and combination doesn't provide a clear path to the numbers that end up in the model. In general, overall estimates fall into three broad categories:

- P90 (Conservative Estimate): Actual future production has a 90 percent probability of meeting or exceeding the estimated recoverable natural gas remaining in the subsurface.
- P50 (Most Likely Estimate): Actual future production has at a 50 percent probability of meeting or exceeding the estimated recoverable natural gas remaining in the subsurface.

- P10 (Optimistic Estimate): Actual future production has a 10 percent probability of meeting or exceeding the estimated recoverable natural gas remaining in the subsurface.

As a result, the model reserve input data consists of all proven reserves and the P50 level of the potential reserves. Using 2005 as the base year, staff's enumeration of reserves follows:

- Proven: 274 Tcf
- Potential: 1480 Tcf

Cost Environment

The marginal cost profile links the marginal cost of production[63] to the quantity of reserves that economic agents can develop. These costs represent the capital expenditures needed to expand the natural gas resource base and vary from location to location. These costs depend on two important parameters:

- Current state of knowledge of the resources
- Current level of technology

To develop the cost profile, an analyst must consider all capital expenditure involved in the F&D of natural gas resources. These F&D costs include:

- Surface preparation cost
- Exploration cost, including seismic surveys
- Drilling cost, including setting the casing[64]
- Completion cost, including hydraulic fracturing if needed
- Dry hole cost (a proportionate cost added to the development cost to account for the cost of nonproductive wells

The summation of all F&D costs by "play" combined with the expected recoverable reserves produces the marginal cost profile as shown in **Figure D-2**. This figure shows the natural gas P50 potential reserve estimate for producing basins and potentially productive play trends in the United States.

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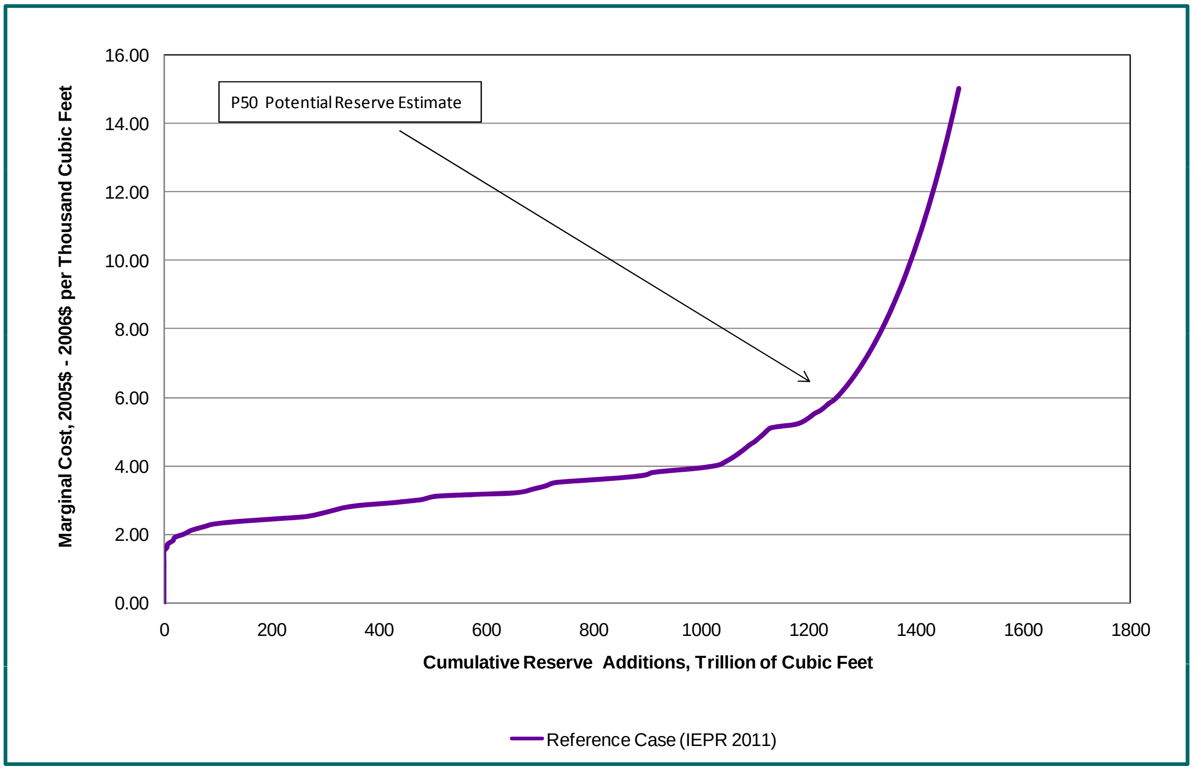
63 This represents the capital portion of the marginal cost of production. The O&M portion appears elsewhere in the WGTM.

64 The string of steel pipe set in drilled hole.

Figure D-2: Marginal Cost Profile

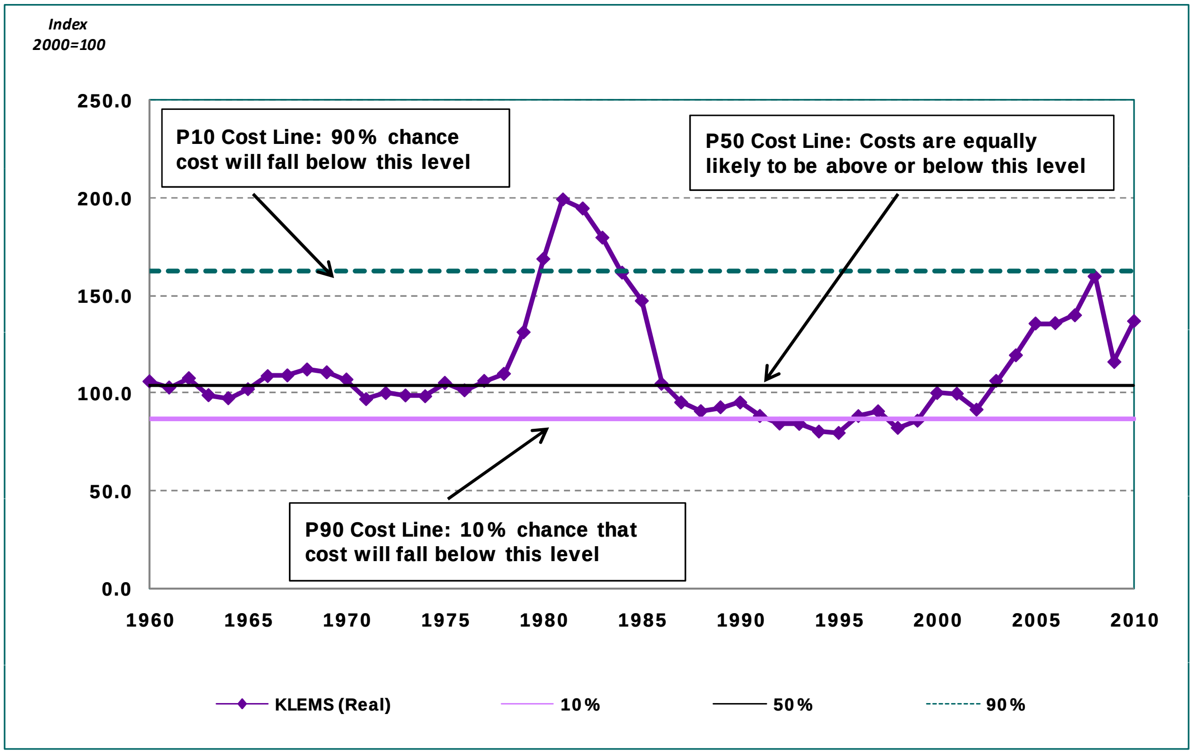


Source: California Energy Commission staff analysis

However, simulations in a long-term model such as the WGTM require a cost environment, that is, a year or group of years that typify the cost parameters in the model. **Figure D-3** shows the real indexed KLEMS[65] cost data for the oil and gas industry.

65 KLEMS means Capital, Labor, Equipment, Materials, and Services. The Bureau of Economic Analysis produces this data.

Figure D-3: Indexed Real Cost for the Oil and Gas Industry



Source: Baker Institute

This figure demonstrates the real cost relationships between 1960 and 2010. Using 2000 as the base year, the 1982 real cost index equaled 195.01, resulting in a 95 percent higher real cost in 1982 than in 2000. Further, since the index in 2010 equaled 137.021, real costs in 1982 exceeded the 2010 cost by about 42 percent.

Staff selected the P50 cost environment, that is, in the long-term environment, costs are equally likely to be above or below this level. As a result, changing the cost environment requires a constant multiplier that falls from the data in **Figure D-3**. As such, moving from a P50 cost environment to a P10 means the constant multiplier equals 1.567 (162.961/103.983)[66]. **Table D-1** displays the constant multiplier the P10 and P90 cost environment.

66 The number 162.961 is the value at the P10 line and 103.983 is the value at the P50 line.

Table D-1: Changing the Cost Environment

Cost Environment	Indexed Cost Value	Constant Multiplier for Changing from P50
P10	162.961	1.567
P50	103.983	1.000
P90	87.148	0.838

Source: Baker Institute

The selection of the cost environment serves as the basis for establishing the link between the marginal cost and reserves additions. **Figure D-2** demonstrates this linkage, and **Table D-2** displays the combination. As a result, model simulations can combine the reserve estimates with the cost environment and produce a series of outcomes that place boundaries on natural gas prices and supply.

As such, the case (P50 Reserve Estimate, P50 Cost Estimate [the shaded cell]) represents staff's reference case. Producing the extreme outer boundaries requires simulations with the following parameters:

- Extreme High Boundary Case: P90 Reserve Estimate, P10 Cost Estimate
- Extreme Low Boundary Case: P10 Reserve Estimate, P90 Cost Estimate

However, given the magnitude of the effort required to simulate the extreme boundaries, staff chose two new cases that widens the range of uncertainty.

The Boundary Cases

In response to comments received from various stakeholders, staff generated two new sensitivity cases that expand the range of prices:

- High Boundary Case: P50 Reserve Estimate, P10 Cost Estimate
- Low Boundary Case: P50 Reserve Estimate, P90 Cost Estimate

Table D-2: Reserve Estimates (RE) and Cost Environment (CE)

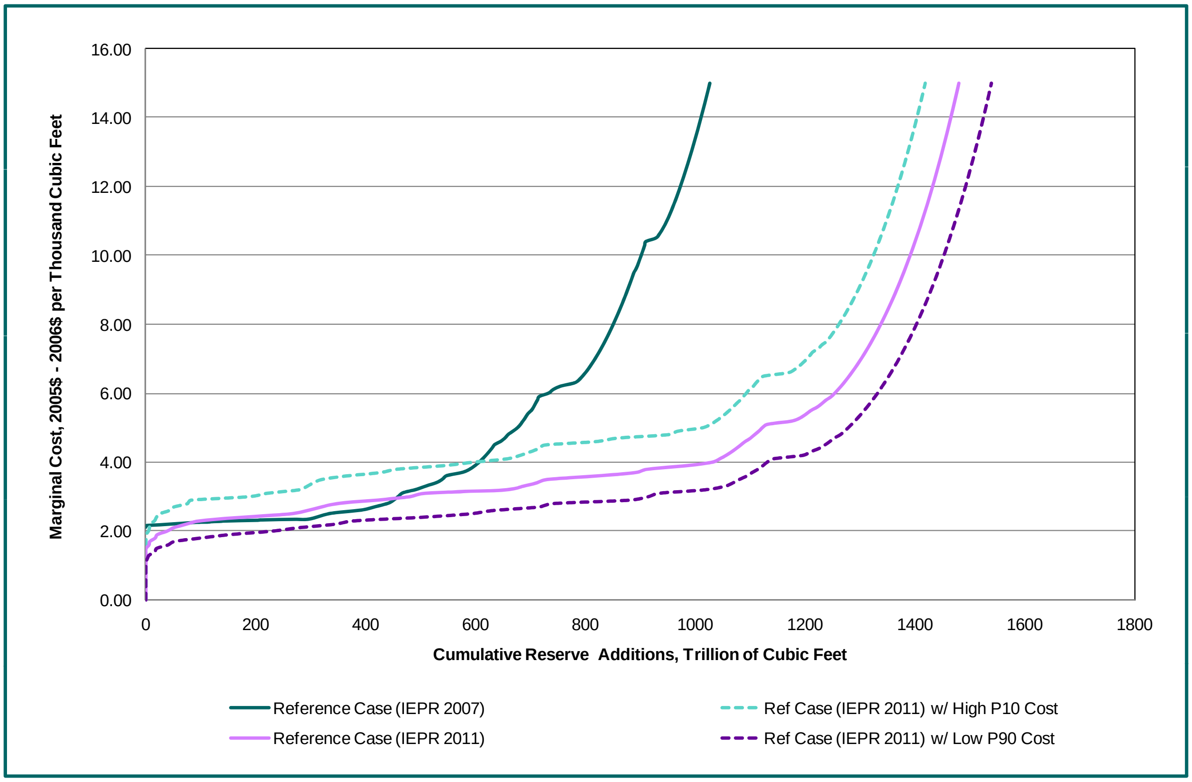
		P10: 10% chance costs reach value or higher	P50: Actual cost value equally likely to be higher or lower than estimate	P90: 90% chance costs reach value or higher
Cost Environment	**P10: 10% chance costs reach value or higher**	Reserve Estimates: Proven: 274 Tcf Potential plus Speculative**: 1970 - 2460 Tcf Cost Environment: Cost going forward approximates real costs in 1984 and 2008	Reserve Estimates: Proven: 274 Tcf Potential: 1480 Tcf Cost Environment: Cost going forward approximates real costs in 1984 and 2008	Reserve Estimates: Proven: 274 Tcf Cost Environment: Cost going forward approximates real costs in 1984 and 2008
Cost Environment	**P50: Actual cost value equally likely to be higher or lower than estimate**	Reserve Estimates: Proven: 274 Tcf Potential plus Speculative**: 1970-2460 Tcf Cost Environment: Cost going forward approximates real costs in 1975, 1986, and 2003	Reserve Estimates: Proven: 274 Tcf Potential: 1480 Tcf Cost Environment: Cost going forward approximates real costs in 1984 and 2008	Reserve Estimates: Proven: 274 Tcf Cost Environment: Cost going forward approximates real costs in 1975, 1986 and 2003
Cost Environment	**P90: 90% chance costs reach value or higher**	Reserve Estimates: Proven: 274 Tcf Potential plus Speculative**: 1970-2460 Tcf Cost Environment: Cost going forward approximates real costs between 1991 and 1999	Reserve Estimates: Proven: 274 Tcf Potential: 1480 Tcf Cost Environment: Cost going forward approximates real costs between 1991 and 1999	Reserve Estimates: Proven: 274 Tcf Cost Environment: Cost going forward approximates real costs between 1991 and 1999

** Approximation assuming a log-normal distribution.

Source: Baker Institute and California Energy Commission staff analysis

However, to complete these cases, staff generated new supply cost curves by shifting the cost environment to P10 in the High Boundary case and to P90 in the Low Boundary case. The curves pictured in **Figure D-4** demonstrate the effective change relative to the Reference Case.

Figure D-4: Marginal Supply Cost Curves of Boundary Cases



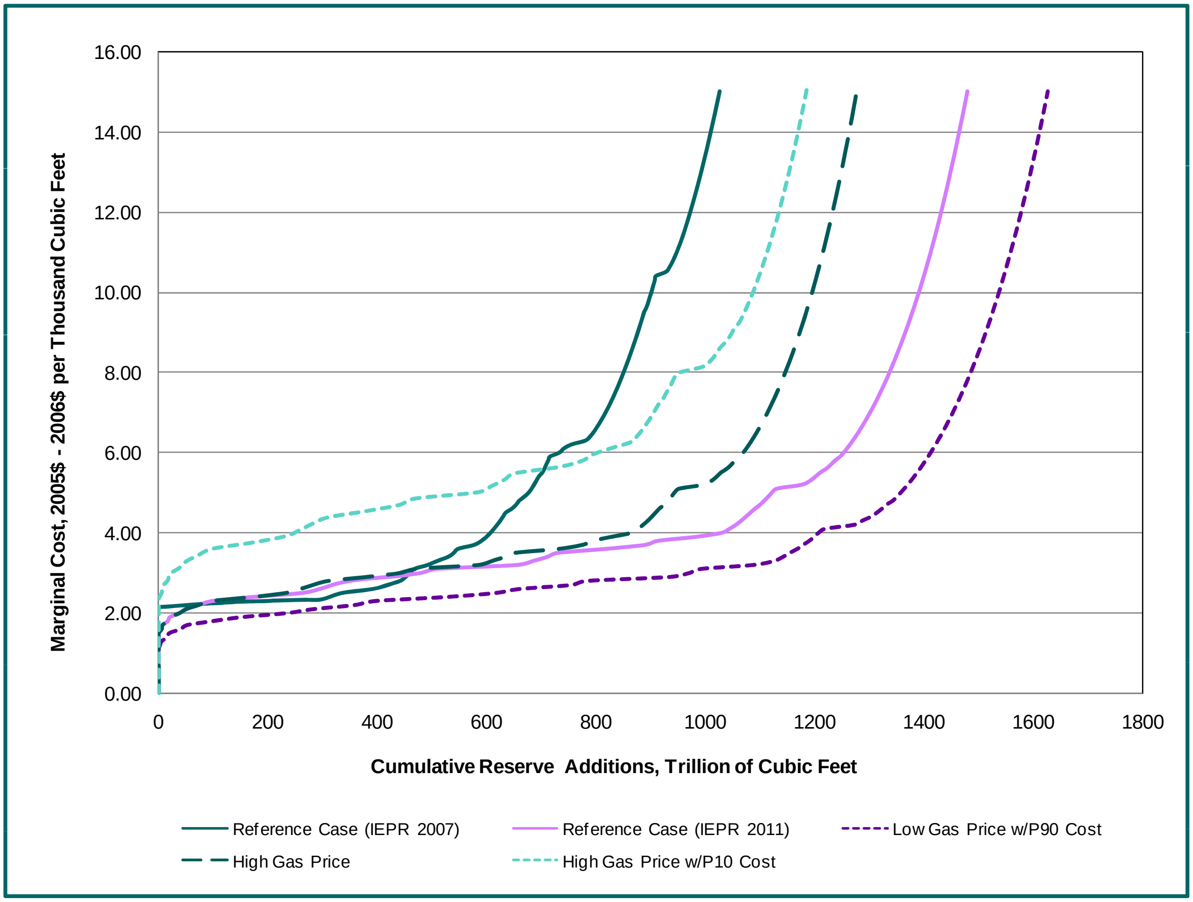
Source: California Energy Commission staff analysis

Staff further tested the boundaries of projected natural gas prices by constructing and running two other cases:

- High Price Case with cost environment changed to P10 from P50
- Low Price Case with cost environment changed to P90 from P50

Figure D-5 displays the effective shift of aggregate supply cost curves for the cases described above relative to the 2007 and 2011 Reference Cases. These supplemental cases attempt to highlight the robustness of the expanded range of natural gas price projections.

Figure D-5: Marginal Supply Cost Curves of Supplemental Boundary Cases



Source: California Energy Commission staff analysis

Operation and Maintenance Costs

In addition to the capital expenditures represented by the supply cost curves, O&M costs play a significant role in the development and production of natural gas resources. This noncapital cost includes all variable expenditures associated with the production of natural gas. Variable expenditures comprise expenses on labor, fluid separation and clean up, water disposal, and other *environmental mitigation*. According to the API, the oil and gas industry spent about $2.3 billion only in O&M cost for environment mitigation in 2009.

In the WGTM, however, staff represents the O&M expenditures as a flat real cost in $2005, a historical average of O&M expenditures in the oil and gas industry. Data used in developing this input parameter originate from sources, such as the API, the EIA, the *Oil and Gas Journal*, the Potential Gas Committee, and others.

APPENDIX E: Comparisons of Staff's Natural Gas Price Results to Others' Forecasts

This appendix makes several comparisons of staff's WGTM results for the annual average equilibrium price of natural gas at Henry Hub to forecasts of Henry Hub prices made by others. Because the details of assumptions and methods underlying many of the other forecasts are not well described or fully documented, extensive point-to-point comparisons to staff's assumptions and methods are not feasible to make.

The following forecasts along with the date of release are included in this appendix:

- Black and Veatch, *Growing Shale Resources* (November 2010)
- Energy Information Administration, *Annual Energy Outlook* (April 2011)
- California Public Utilities Commission, *2009 and 2011 Market Price Referent* (December 2009 and December 2011)
- ICF, *North American Midstream Infrastructure Through 2035*, INGAA Foundation, Inc. (June 2011)
- International Energy Agency, *World Energy Outlook* (June 2011)
- Northwest Power and Conservation Council, *Update to the Council's Forecast of Fuel Prices* (August 2011)
- Bentek, Forward Curve Quarterly (3rd Quarter 2011)
- Deloitte's *Navigating a Fractured Future: Insights Into the Future of the North American Natural Gas Market* (2011)

Black and Veatch, *Growing Shale Resources*, November 2010

Black and Veatch (B&V) [67] uses its own model and provides forecasting services for its clients. Since the Energy Commission does not subscribe to B&V forecasting services, it is difficult to compare its natural gas price forecast with that of the Energy Commission. **Table E-1**, **Table E-2**, and **Table E-3** list the assumptions of the B&V natural gas price forecast's three cases.

67 See http://www.bv.com/Downloads/Resources/Reports/Growing_Shale_Resources_FullReport.pdf for the full report.

Table E-1: Black and Veatch Reference (Mid-Price) Case Assumptions

Supply	
Land Use	10%-20% of Marcellus reserves inaccessible
Fiscal Regime	Baseline Severance and Royalty Assumptions for U.S. and Canada
Shape of F&D Curve	Moderate Cost Escalation
Water Costs	$0.75/Mcf for Marcellus, $0.25/Mcf cost for all other shales
LNG	2011 to 2014 Compound Annual Growth Rate of 3.6% 13.4 Bcf/d by 2044
Demand	
Assumption Source	B&V EMP Spring 2010
Residential and Commercial	0.7% Compound Annual Growth Rate for 2010 to 2035
Industrial	0.9% Compound Annual Growth Rate for 2010 to 2035
Power Generation	2.3% Compound Annual Growth Rate for 2010 to 2035
Electricity Load Growth	1.1% Compound Annual Growth Rate for 2010 to 2034
Renewable	108 GW additional nameplate capacity by 2034
Nuclear	41 GW additional nameplate capacity by 2034
GHG Allowance Prices	$29/short ton of CO_2 in 2016

Source: http://www.bv.com/Downloads/Resources/Reports/Growing_Shale_Resources_FullReport.pdf

Table E-2: Black and Veatch High-Price Scenario Assumptions

Supply	
Land Use	35% Marcellus, 10% of all other shale reserves inaccessible
Fiscal Regime	10% Severance Tax in United States; 15% increase in BC and AB Royalty Rates
Shape of F&D Curve	Rapid Cost Escalation
Water Costs	$1.38/Mcf cost for all shales
LNG	2011 to 2014 Compound Annual Growth Rate of 3.6% 13.4 Bcf/d by 2044
Demand	
Assumption Source	B&V EMP Spring 2010
Residential and Commercial	0.7% Compound Annual Growth Rate for 2010 to 2035
Industrial	0.9% Compound Annual Growth Rate for 2010 to 2035
Power Generation	2.3% Compound Annual Growth Rate for 2010 to 2035
Electricity Load Growth	1.1% Compound Annual Growth Rate for 2010 to 2034
Renewable	108 GW additional nameplate capacity by 2034
Nuclear	41 GW additional nameplate capacity by 2034
GHG Allowance	Prices $29/short ton of CO_2 in 2016

Source: http://www.bv.com/Downloads/Resources/Reports/Growing_Shale_Resources_FullReport.pdf

Table E-3: Black and Veatch Low-Price Scenario Assumptions

Supply	
Land Use	10% of Marcellus reserves inaccessible
Fiscal Regime	Moderate Severance and Royalty Assumptions for U.S. and Canada
Shape of F&D Curve	On par with Conventional Resource Cost Escalation
Water Costs	$0.75/Mcf for Marcellus, $0.25/Mcf cost for all other shales
LNG	AEO 2010 Assumptions: 4 Bcf/d in 2020 declining to 2.3 Bcf/d from 2030-2044
Demand	
Assumption Source	EIA AEO 2010
Residential and Commercial	0.3% Compound Annual Growth Rate for 2010 to 2035
Industrial	0.4% Compound Annual Growth Rate for 2010 to 2035
Power Generation	0.5% Compound Annual Growth Rate for 2010 to 2035
Electricity Load Growth	0.9% Compound Annual Growth Rate for 2010 to 2035
Renewable	40.5 GW additional nameplate capacity by 2034
Nuclear	10.4 GW additional nameplate capacity by 2034
GHG Allowance Prices	No CO_2 cost

Source: http://www.bv.com/Downloads/Resources/Reports/Growing_Shale_Resources_FullReport.pdf

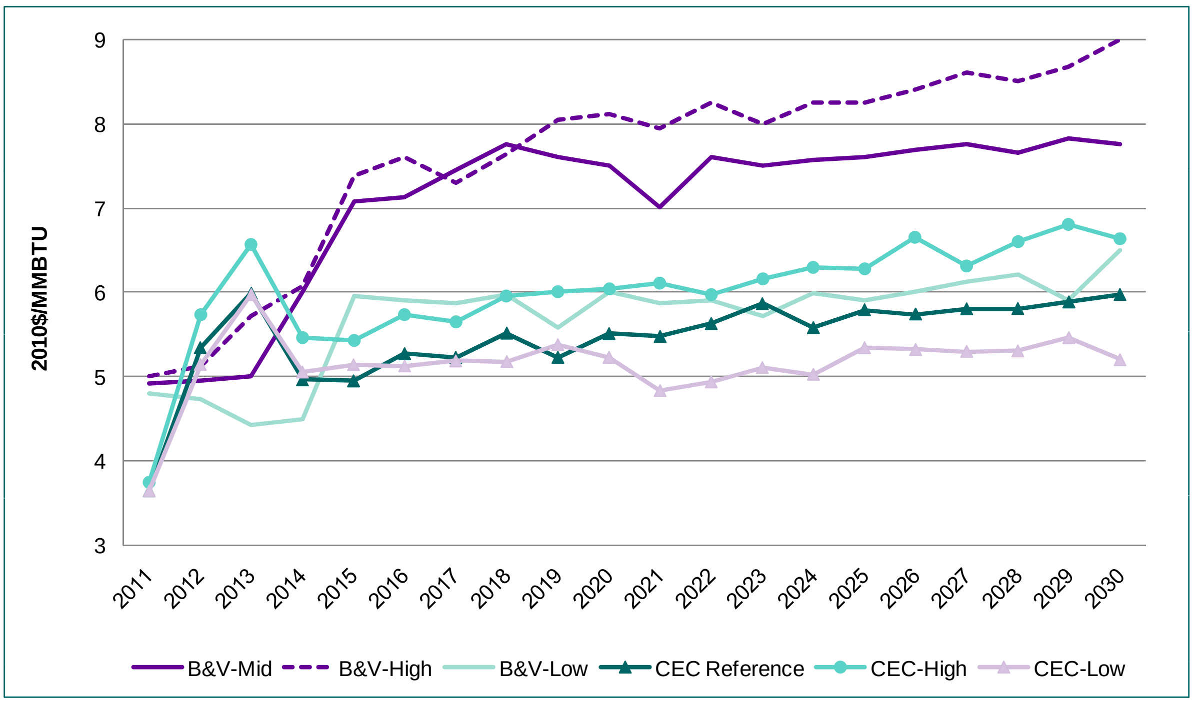
Comparison to Staff Assessment

Energy Commission staff has estimated the natural gas price numbers from B&V by looking at Figure 1-2 on page 8 in its report (http://www.bv.com/Downloads/Resources/Reports/Growing_Shale_Resources_FullReport.pdf). Based on these estimates, it appears that overall the B&V price forecasts are higher than the Energy Commission's staff assessment price forecasts. Although it is hard to compare price forecasts because of differing input assumptions and models, a few potential reasons for the differences in forecast values can be surmised.

One similarity between the B&V forecast and the Energy Commission forecast is that the B&V mid-price case shows a price jump from about $5/MMBtu to $7/MMBtu from 2013 to 2015 while the Energy Commission's staff assessment Reference Case shows a price jump of similar magnitude ($2.34/MMBtu) between 2011 and 2013. The 2011 – 2013 price jump seen in the Energy Commission's staff assessment can be attributed mainly to a technical issue in the model that is addressed in Chapter 3; Chapter 3 provides a more detailed description of natural gas price output for 2011 – 2013). Thus, the natural gas price model results discussed below will focus on the 2014 – 2030 period.

In all three B&V cases, some portion of the Marcellus shale is assumed to be inaccessible. The Energy Commission's staff assessment makes a similar assumption only in its High Price and Shale Constrained cases. In the B&V's mid price case, a water cost of $0.75/Mcf for Marcellus shale is assumed. In the High Price case, the Energy Commission's staff assessment assumes an environmental cost of $0.40/Mcf in the Shale Constrained and High Price cases. Looking at the input assumptions of B&V, it appears the assumptions represent a higher cost environment than do the assumptions of the Energy Commission's staff assessment forecasts. **Figure E-1** illustrates the price results of B&V and the Energy Commission staff analysis.

Figure E-1: Henry Hub Price Projections for the Energy Commission and Black and Veatch



Source: http://www.bv.com/Downloads/Resources/Reports/Growing_Shale_Resources_FullReport.pdf

Energy Information Administration, *Annual Energy Outlook 2011*, April 26, 2011

The EIA ran several natural gas price cases.[68] The cases that are most comparable to the Energy Commission's staff assessment natural gas price forecast cases are examined.

68 http://www.eia.gov/forecasts/aeo/

The AEO Reference Case assumes world gas prices of $78, $95, and $125 per barrel in 2010, 2015, and 2035, correspondingly. In addition, the case also assumes a GDP annual growth of 2.7 percent from 2009-2035.

The AEO High Shale EUR (estimated ultimate recovery) Case assumes a resource base 50 percent higher than in the staff's Reference Case. The High Shale EUR Case assumes that the EUR per shale gas well is 50 percent higher than in the staff's Reference Case (1,230 Tcf instead of 827 Tcf) due to better development and production techniques. The assumed lower cost per unit of production caused this case to result in the lowest gas prices.

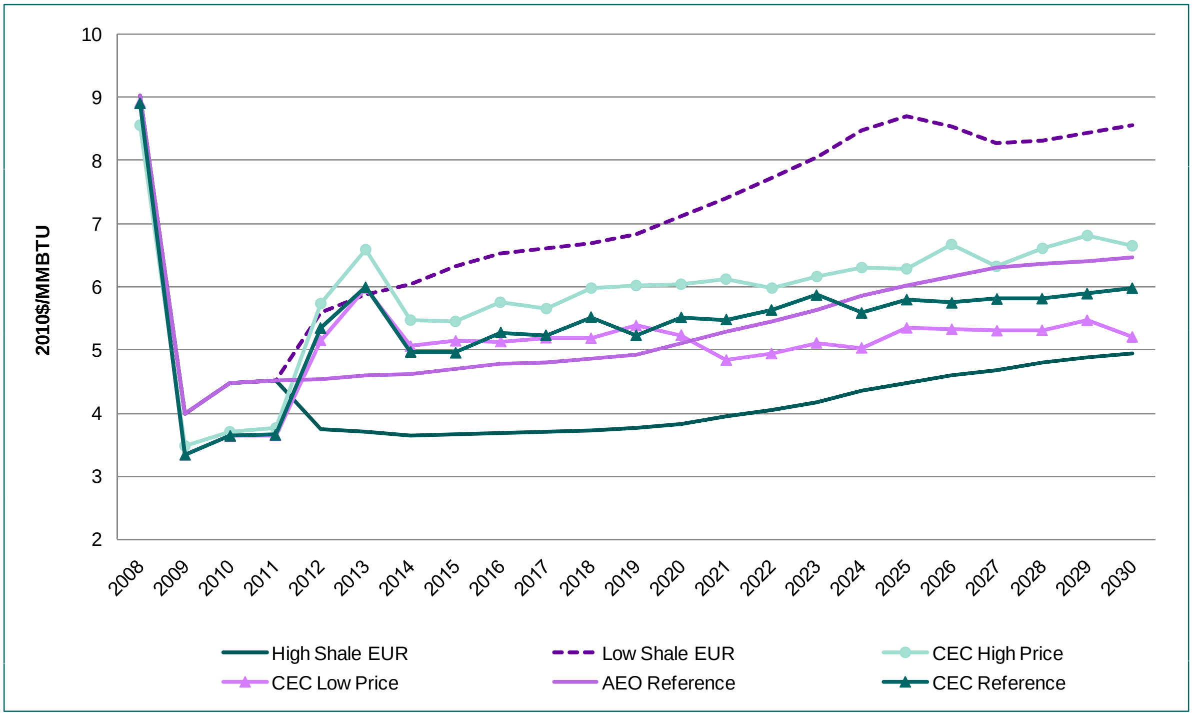
The AEO Low Shale EUR Case assumes the resource base is 50 percent lower than in the staff's Reference Case: 423 Tcf instead of 827 Tcf. The EUR per shale gas well is 50 percent lower than in the Reference Case, from faster than expected rates of decline in gas production.

Comparison to Staff Assessment

EIA uses the National Energy Modeling System (NEMS) while the Energy Commission staff uses the MarketBuilder platform. Even with the same assumptions, it may not be possible to see exactly the same results based on how the algorithms in each model work. Because these two model platforms are different, it may not be possible to have exactly the same assumptions in both models.

The cases from the *AEO 2011* used for comparisons are the AEO Reference Case and the AEO High and Low Shale EUR Recovery Cases. The AEO High and Low Shale EUR Recovery Cases bound the Energy Commission's staff assessment High and Low Price Cases from 2014 onward. The *AEO 2011* High and Low Shale EUR Cases have stronger assumptions about shale than do the High Price and Low Price Cases of the Energy Commission's staff assessment, thus a wider range is expected in the *AEO 2011* cases. The *AEO 2011* cases all appear to grow at a slightly higher rate than the Energy Commission's staff assessment cases. Looking at both Reference Cases from 2014 – 2030, the Energy Commission has an average growth rate of 1.22 percent while the *AEO 2011* has one of 2.14 percent. **Figure E-2** illustrates these cases.

Figure E-2: Comparison of the Energy Information Administration Price Forecast to the Energy Commission Staff Analysis



Source: http://www.eia.gov/forecasts/aeo/

Data: http://www.eia.gov/oiaf/aeo/tablebrowser/

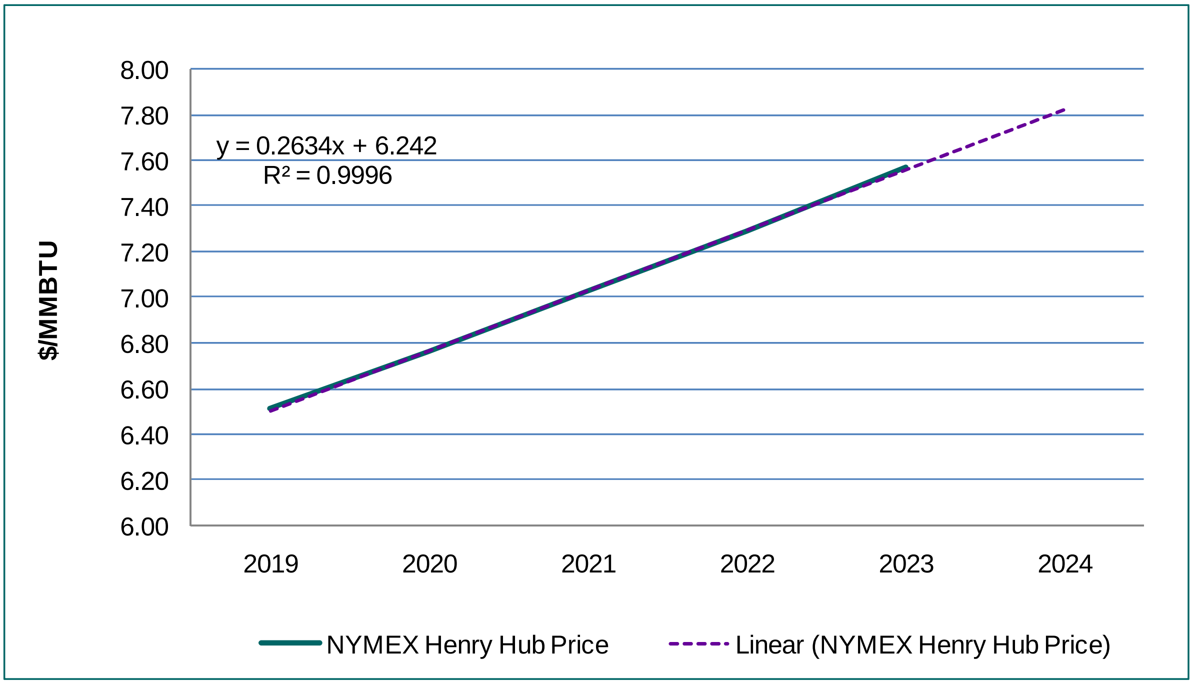
California Public Utilities Commission, *2009 and 2011 Market Price Referent*

The MPR[69] simulates the cost of gas over the entire life of a combined cycle gas turbine (the proxy plant) long-term contract based on market prices and fundamental forecasts. The MPR represents what it would cost to own and operate a baseload combined cycle gas turbine power plant over various periods. The cost of electricity generated by such a power plant, at an assumed technical capacity factor and set of costs, is the proxy for the long-term market price of electricity established by the CPUC. The 2009 MPR values were for use in the 2009 RPS solicitations. The MPR does not represent the cost, capacity, or output profile of a specific type renewable generation technology. The MPR represents the presumptive cost of electricity from a nonrenewable energy source, which the CPUC, in D.03-06-071, held to be a natural gas-fired baseload or peaker plant (D.04-06-015, p. 6, n.10). The MPR is updated every couple of years. The last update was done in December 2011.

69 For more information on the CPUC's MPR, see http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr

Methodology: The MPR forecast uses 12 years of New York Mercantile Exchange (NYMEX) forward price data. The MPR Gas Methodology uses a 22-trading day average of NYMEX forward prices. For example, the 2009 MPR takes NYMEX forward prices from the 22 trading days between July 27, 2009 and August 25, 2009. For year 13, a 5-year trend (years 8-12 of NYMEX data) is used to mitigate the effect of one price in the thinly traded outer years of the NYMEX futures market on the long-term forecast. **Figure E-3** shows NYMEX Henry Hub prices using this methodology. For years 14 and on, the CPUC uses an average growth rate of three private forecasts to which the agency subscribes.

Figure E-3: Market Price Referent New York Mercantile Exchange Henry Hub Prices



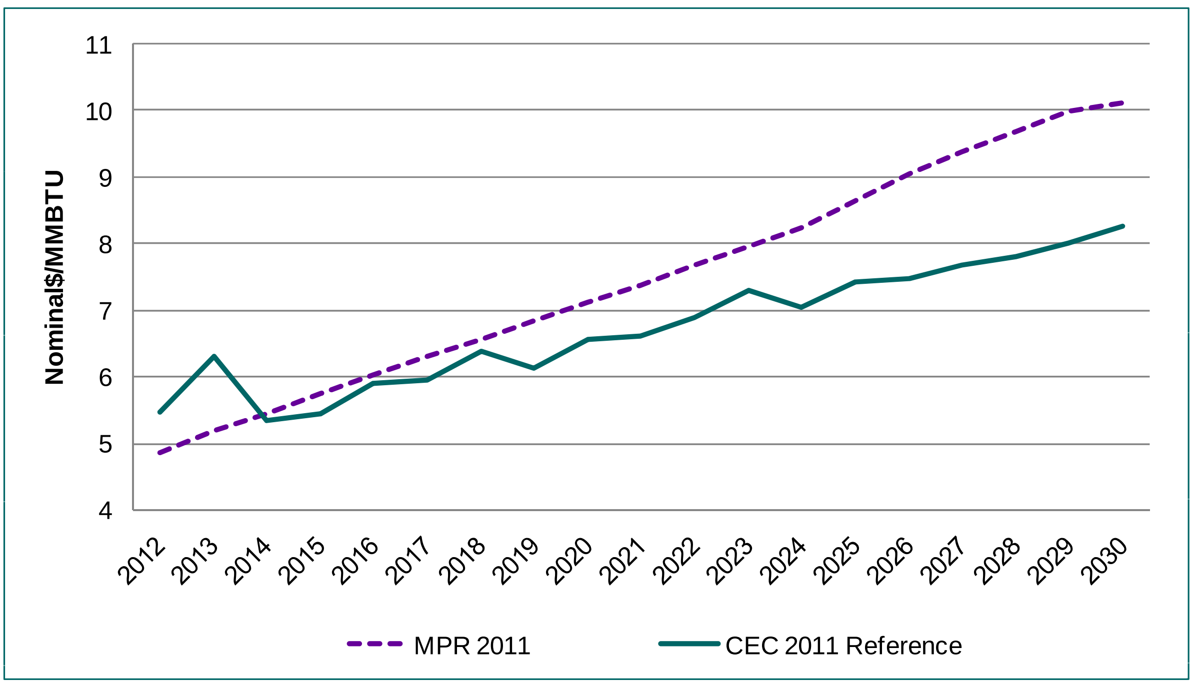
Source: 2009 MPR, http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr

Comparison to Staff Assessment

Although the CPUC came out with an MPR in December 2011, Energy Commission staff has been working through the summer and fall of 2011 on this report and generated a "potential" MPR using similar methodology that the CPUC staff used for 2009 MPR. To produce this "potential" MPR, the Energy Commission staff used July 27, 2011, and August 25, 2011, of NYMEX natural gas prices for the first 12 years of the forecast. For the year 13, staff used the 5-year trend as described in the Methodology section. Since the Energy Commission does not subscribe to private forecasts for the remaining years, Energy Commission staff used the growth rate from the CPUC's 2010 Long Term Procurement

Plan (LTPP) natural gas price forecast.[70] This "potential" MPR price forecast was compared to the Energy Commission's Reference Case. The MPR methodology generates only one forecast with no additional sensitivities or changed cases, while the Energy Commission staff generated several other scenarios and sensitivities. The "potential" 2011 MPR price forecast, as developed by Energy Commission staff, follows closely the Energy Commission's 2011 Reference Case price forecast up through to 2025. After 2025, the "potential" 2011 MPR forecast appears to grow slightly faster than the Energy Commission's staff assessment forecast. Because the approach to forecasting is different between the Energy Commission staff and the CPUC staff, it is difficult to directly compare these two forecasts. The "potential" 2011 MPR is based partially on consumers' willingness to pay at the time NYMEX data is collected. On the other hand, the Energy Commission's staff forecast is based on supply and demand fundamentals. **Figure E-4** illustrates this comparison.

Figure E-4: Henry Hub Prices, Energy Commission Reference Case vs. "Potential" Market Price Referent



Source for methodology: 2011 MPR model, http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr

NYMEX prices from: http://intelligencepress.com/

Growth rate for years 2025-2030: Evaluation Metric Calculator 2010 LTPP (E3: Energy + Environmental Economics, April 2011 Evaluation Metric Calculator at http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/LTPP2010/LTPP_System_Plans.htm

70 Evaluation Metric Calculator 2010 LTPP (E3: Energy + Environmental Economics, April 2011), http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/LTPP2010/LTPP_System_Plans.htm

ICF, North American Midstream Infrastructure Through 2035, INGAA Foundation, Inc., June 28, 2011

ICF's reference case[71] assumes the U.S. economy grows at 2.8 percent per year. Oil prices in the United States average about $80 per barrel in real terms through 2035. Demographic trends remain consistent over the past 20 years. U.S. population growth averages about 1 percent per year. Electric load growth averages 1.3 percent per year. This case also includes a charge on CO_2 starting in 2018 reflecting the continuing lack of consensus in Congress and the possibilities for direct regulation of CO_2. The case generally leads to retirement and replacement of some coal-generating capacity with gas-generating capacity.

ICF assumes the following power plant mix: renewable up to meet states' RPS, coal generation down, and other forms of nongas generation slightly down. Gas generation grows to fill the gap between electric load and the total amount of generation from other types of generation.

The ICF's reference case also assumes adoption of demand-side management (DSM) programs and conservation and efficiency trends continue, consistent with recent history. Compressed natural gas vehicles are assumed to be limited to commercial fleets and buses.

- Weather is assumed to be consistent with past 30 year averages.
- Gas supply development is permitted to continue at recently observed activity levels.
- No significant restrictions on permitting and hydraulic fracturing beyond current restrictions occur.
- No significant hurricane disruptions to natural gas supply (20-year average) occur.
- No Arctic projects (specifically no Alaska and Mackenzie Valley gas pipelines) are built.
- Net LNG exports occur only at the Kitimat facility (no net LNG exports from elsewhere in the United States and Canada).
- Near-term midstream infrastructure development is assumed per project announcements.

Unplanned projects are included when market signals need of capacity, and there are no significant delays in permitting and construction. **Table E-4** summarizes the trends of ICF's reference case price forecast.

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71 Pages 17-18, http://www.energy.ca.gov/2011_energypolicy/documents/2011-09-27_workshop/comments/INGAA_Natural_Gas_Market_Assessment_Reference_Case_and_Scena_TN-62246.pdf.

Table E-4: Summary of Key Trends in ICF's Reference Case (Tcf)

United States and Canada	2010	2020	2035	% Change 2010 to 2020	% Change 2010 to 2035
Gas Consumption	27.0	33.6	39.7	24	47
Gas Use in Power Generation	7.4	12.0	17.0	62	129
Gas Production	27.2	34.2	40.3	26	48
Conventional Onshore Gas Production	12.9	11.1	10.3	14	20
Unconventional Onshore Gas Production	11.9	21.1	27.7	77	132
Offshore Production	2.4	1.9	2.3	21	-2
Shale Gas Production	4.6	12.6	18.9	274	308
Net LNG Imports	0.5	0.6	1.0	20	120
Net Exports to Mexico	0.3	0.5	1.1	66	245

Source: Pages 17-18, http://www.energy.ca.gov/2011_energypolicy/documents/2011-09-27_workshop/comments/INGAA_Natural_Gas_Market_Assessment_Reference_Case_and_Scena_TN-62246.pdf

Comparison to Staff Assessment

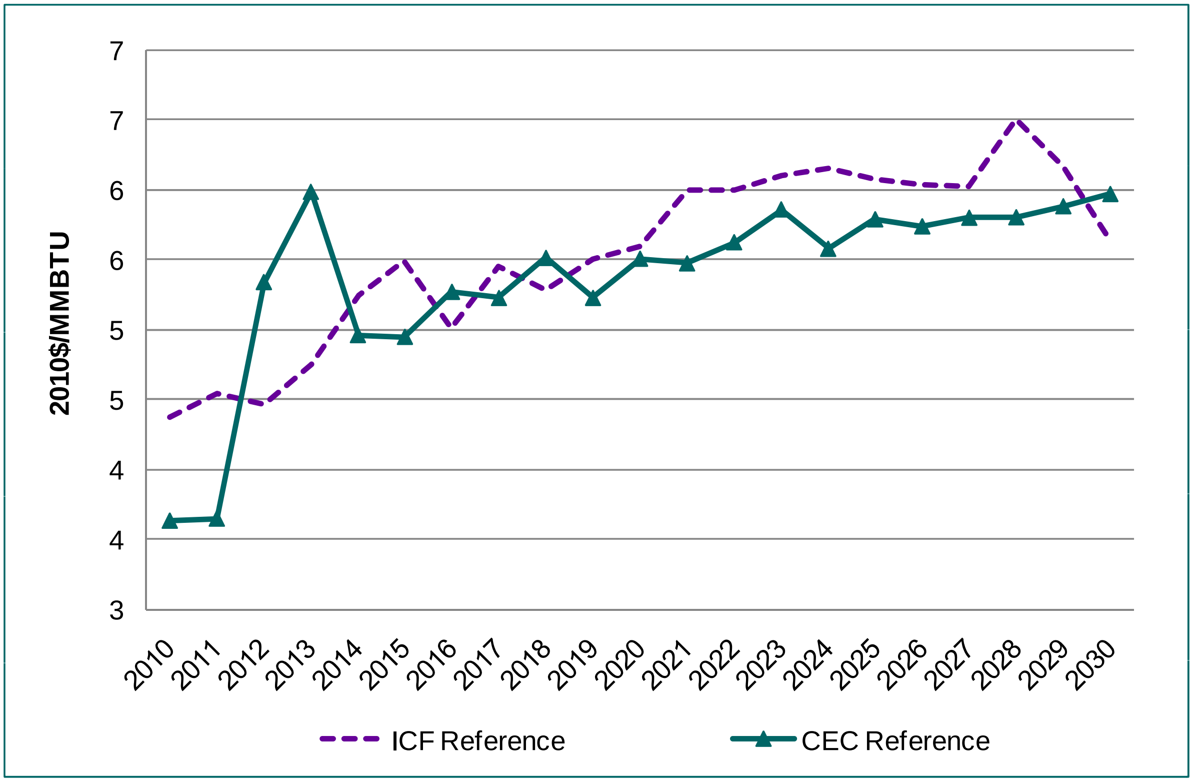
ICF's and Energy Commission staff's assumptions to generate the natural gas forecast for the reference cases are similar in numerous aspects, except in few cases. For example, ICF assumes that net LNG exports occur only at Kitimat, while the Energy Commission staff in its Reference Case does not restrict LNG exports to one location, but allows exports from any facility. Although ICF does not explain how DSM and efficiency programs are built into the model, ICF assumes DSM programs are adopted and conservation and efficiency trends continue, consistent with recent history, while the Energy Commission's staff assessment for the Reference Case makes no direct assumptions about DSM programs. When comparing total gas demand, gas demand for power generation, as well as gas supply from **Table E-4** to the Energy Commission's Reference Case trends in **Table 5** and **Table 6** of Chapter **3,** ICF results are slightly higher than staff's results.

Energy Commission staff estimated price projections for the ICF forecasts using the graph in its report. The actual data was unavailable to Commission staff. Since ICF provided only one case, this was compared to the Energy Commission's Reference Case. Also, ICF uses the Gas Market Model modeling platform, which is a nonlinear programming model similar to the MarketBuilder model used by Energy Commission staff. The two models incorporate the economic interactions of supply, price, demand, and pipeline infrastructure to generate equilibrium in the gas market.

The ICF forecast prices do not increase as rapidly in the early years as does the Energy Commission staff's forecast. From 2011 – 2013 the Energy Commission's staff assessment prices increase by $2.34/MMBtu while from 2012 – 2015 the ICF prices increase by

$1.02/MMBtu. The 2011 – 2013 price jump seen in the Energy Commission's staff assessment can be attributed to a technical issue in the model, which is addressed in Chapter 3. These two forecasts have similar growth rates for most of the forecast period (2010 – 2030). From 2016-2030, ICF Henry Hub prices grow at an average rate of 0.950 percent while the Energy Commission forecast prices grow at 0.947 percent. **Figure E-5** compares the Energy Commission staff analysis to the ICF price forecast.

Figure E-5: Henry Hub Prices, ICF vs. Energy Commission



Source: Pages 14, 15 http://www.energy.ca.gov/2011_energypolicy/documents/2011-09-27_workshop/comments/INGAA_Natural_Gas_Market_Assessment_Reference_Case_and_Scena_TN-62246.pdf.

International Energy Agency, *World Energy Outlook 2011*, June 6, 2011

This section will compare natural gas prices from the Energy Commission's staff assessment forecasts and the U.S. gas prices from the International Energy Agency World Energy Outlook (IEA, WEO).[72] Care needs to be taken in interpreting the results as the comparison is not Henry Hub price to Henry Hub price, but rather Henry Hub price

72 http://www.worldenergyoutlook.org/golden_age_gas.asp.

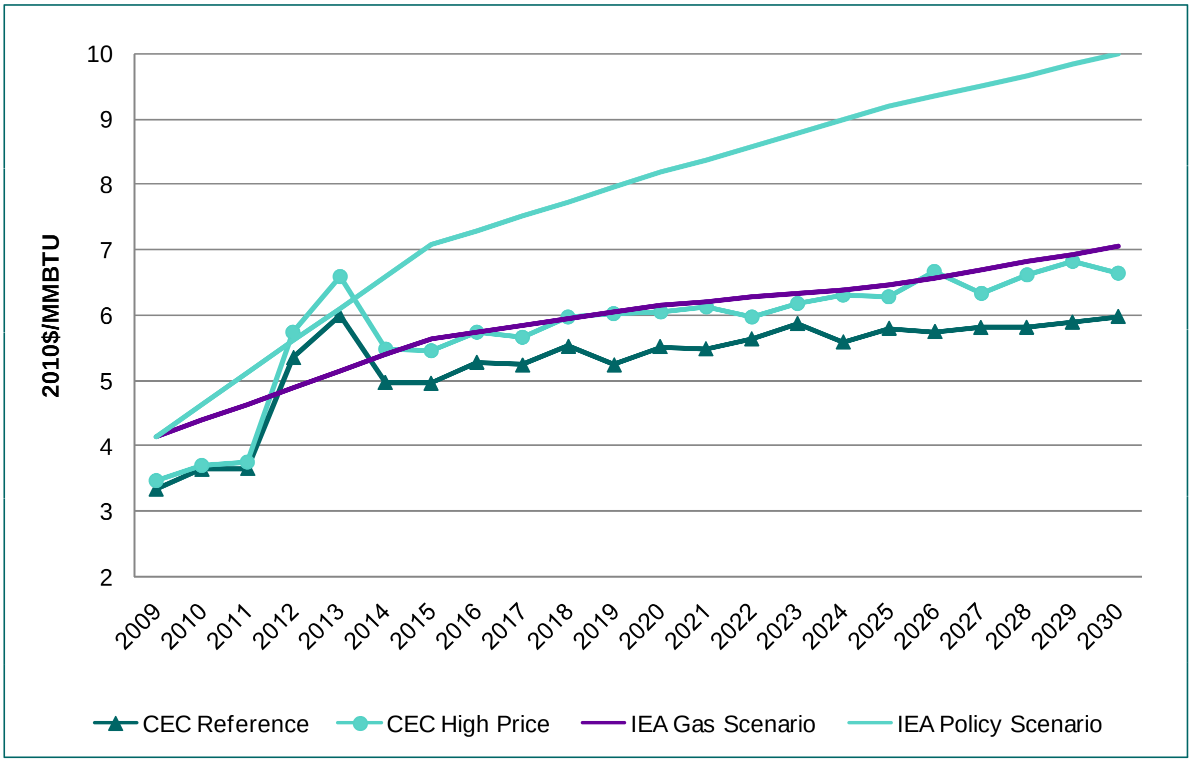
developed by the Energy Commission staff to a proxy for Henry Hub, as developed by the IEA.[73] In addition, the IEA WEO only has price data for 2009, 2015, 2020, 2025, and 2030; the other price data were estimated by Energy Commission staff using linear extrapolation.

Comparison to Staff Assessment

The IEA WEO prices in the IEA Gas Scenario and IEA Police Scenario are higher than the Energy Commission staff's Reference Case and High Price Case. The IEA WEO Gas Scenario has roughly the same growth rate as both of the Energy Commission's staff assessment cases while the IEA WEO Policy Scenario has a slightly higher growth rate. Both IEA WEO cases do not appear to have the sharp jump in prices in the 2011 – 2013 time frame as do the Energy Commission's High Price and Reference Cases. As indicated previously the 2011 – 2013 price jump seen in the Energy Commission's staff assessment is attributable to a technical issue in the model, which is addressed in Chapter 3. However, the price points between 2009 and 2015 in the IEA cases were estimated by linear extrapolation, which may mask any steep price movements. With additional input assumptions and more data from IEA WEO, a more detailed comparison could be made between the Energy Commission staff's forecasts and IEA's. **Figure E-6** illustrates these findings.

73 The U.S.'s price is used as a proxy for prices prevailing on the domestic market. Energy Commission staff assumes this price reflects the Henry Hub price as Henry Hub is considered a national benchmark price.

Figure E-6: Henry Hub Prices, International Energy Agency vs. Energy Commission



Source: http://www.worldenergyoutlook.org/golden_age_gas.asp

Northwest Power and Conservation Council, Update to the Council's Forecast Fuel Prices, December 2010

The natural gas price forecast assumptions by the Northwest Power and Conservation Council (NWPCC)[74] are qualitative compared to the Energy Commission's staff assessment forecast. For example, in the Energy Commission staff's High Price Case, staff assumes that 50 GW of coal-fired generation will be removed from the power pool in the United States by 2020, while the NWPCC assumes faster conversion from coal to natural gas power generation. The NWPCC developed several scenarios including a low, medium low, medium, medium high, and high. Energy Commission staff chose to compare the NWPCC low, medium, and high cases to Energy Commission staff's Reference Case, High Price Case, and Low Price Case.

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74 Update to the Council's Forecast of Fuel Prices (page 7, Table 4) http://www.nwcouncil.org/energy/powerplan/6/default.htm.

Northwest Power and Conservation Council Assumptions

The following are some of the assumption that NWPCC identified for its cases:

Medium Natural Gas Price Case

- Moderate economic recovery in United States and worldwide
- Shale gas production in the United States and worldwide continues to keep downward pressure on prices
- Some environmental opposition to shale gas development
- United States and Canada possible sources of LNG exports
- Power plant conversions from coal to gas continuing

Low Natural Gas Price Case

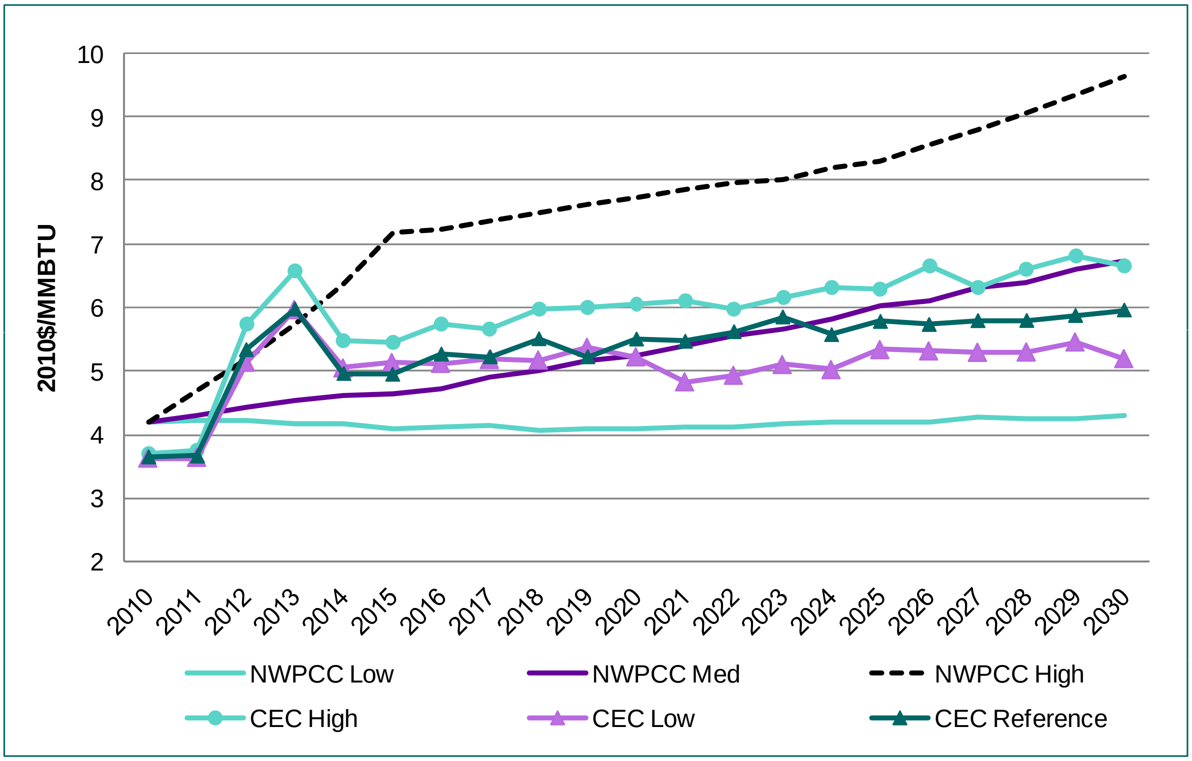
- Slow economic recovery, United States and worldwide
- No serious environmental opposition to shale gas development
- Increased availability of shale gas production in the United States and worldwide
- High hydrocarbon prices (natural gas liquids including propane, ethane, butane, and pentane)
- Delay in environmental regulation (CO_2 tax)
- Delay in conversion from coal to natural gas
- No demand from natural gas vehicle development

High Natural Gas Price Case

- Faster economic recovery in the United States and worldwide
- Opposition to shale gas production in the United States and worldwide reduces supply
- Strict environmental regulation (CO_2 tax); faster conversion from coal to natural gas power plants
- More natural gas vehicles in response to CO_2 tax; demand for natural gas increases

The NWPCC has a much wider range of natural gas prices among its forecast cases than the Energy Commission staff's cases. **Figure E-7** illustrates this finding.

Figure E-7: Henry Hub Prices, Northwest Power and Conservation Council vs. Energy Commission



Source: Update to the Council's Forecast of Fuel Prices (page 7,Table 4)
http://www.nwcouncil.org/energy/powerplan/6/default.htm

The NWPCC's high price case is its only case that shows a near-term price jump similar to that of the Energy Commission staff's assessment cases, although the price jump in NWPCC high case is not as large as the Energy Commission staff's cases. The NWPCC high case is the only one that assumes restrictions on shale gas development, which reduces supply of gas and might be causing the price jump. From 2010 to 2015 the NWPCC high case jumps $2.92/MMBtu (a 69 percent increase) while the Energy Commission's High Case jumps $2.88/MMBtu from 2010 – 2013 (78 percent increase.) Although the overall increases are similar, the Energy Commission staff's forecast occurs over a shorter amount of time.

Bentek Energy LLC, *Forward Curve Quarterly*, 3rd Quarter, 2011

Bentek generates a quarterly forecast of natural gas prices at Henry Hub for the following five years. The prices are annual averages that Energy Commission staff derived from the monthly forward curve that Bentek produced.

Bentek Assumptions[75]**:** Bentek's forecast for the third quarter of 2011 does not assume laws and regulations currently in force as does, for example, the *EIA AEO*, but applies a test of "reasonableness" based on Bentek's own assessments of the most likely market reaction to regulations. For example, Bentek assumes U.S. EPA regulations affecting coal-fired generation will be scaled back because grid operators will not be able to arrange for full replacement with gas-fired generation and the pipeline infrastructure will not be available to support it; reliability will be compromised so often that U.S. EPA will be compelled to revisit the regulations. This quarterly forecast assumes U.S. imports from Canada will decline by 2.0 Bcf/d by 2016. Exports of gas from Canada to California will be lower as Rockies gas via the Ruby Pipeline displaces imported gas to California. This case assumes Northeast gas imports will also be curtailed because of strong Marcellus shale production and additional pipeline capacity enters into the region.

Bentek also assumes that residential/commercial demand is expected to grow from 27 Bcf/d in 2011 to 29 Bcf/d in 2016. In addition, a 1.7 billion cubic feet equivalent per day (Bcfe/d) of fuel oil will be displaced by natural gas over the next five years. By 2016 natural gas demand for power generation is expected to average 26.7 Bcf/d, a 6.4 Bcf/d increase over 2011 levels.

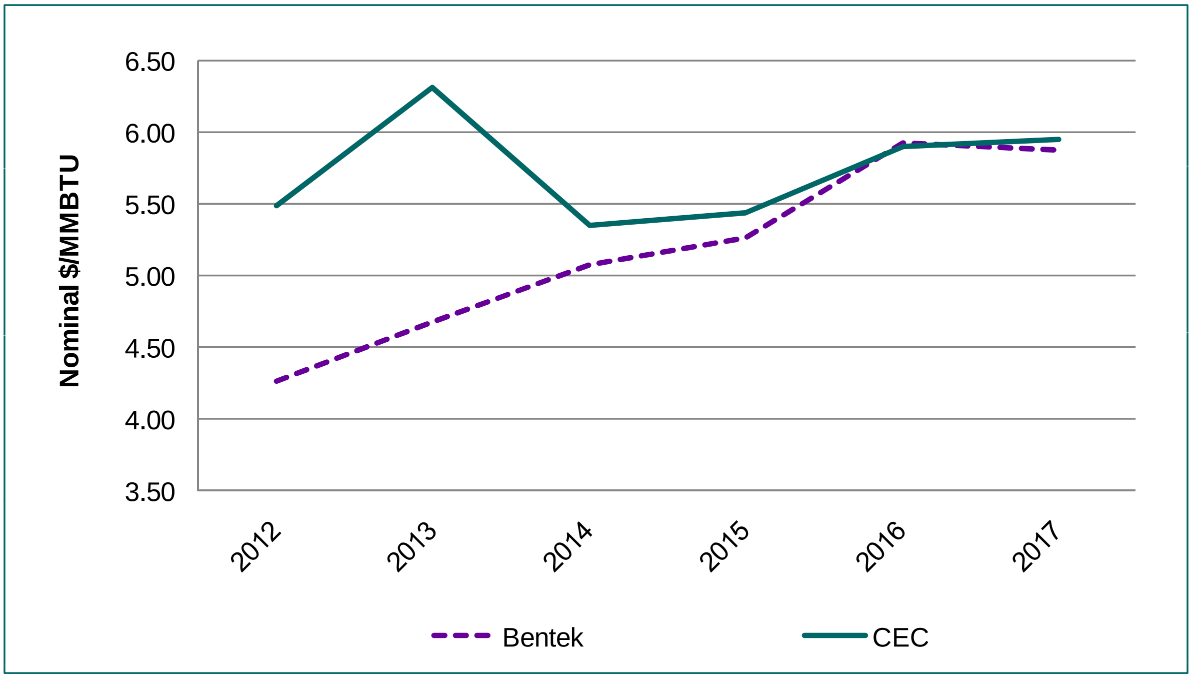
Comparison to Staff Assessment

Bentek uses a proprietary model that it created in-house. Bentek only has one scenario available, so that will be compared to the Energy Commission staff's Reference Case. Although Bentek does not disclose whether its price forecast is in real or nominal terms, Energy Commission staff assumes that its forecast is in nominal dollars, since Bentek always compares its forecast to NYMEX prices, which are assumed to be in nominal dollars.

As indicated previously, the Energy Commission staff's price forecast jumps up then goes backs down from 2012 to 2013 while Bentek's does not. However, from 2014 – 2017 the two forecasts look remarkably similar. The slopes of the price plots are almost the same after 2014. In fact, in 2017 the two prices differ by only $0.08/MMBtu. **Figure E-8** illustrates these findings.

75 http://www.benport.com/benport/DisplayReportNews.aspx?LOC=1&ID=0&doc=BENTEK_ForwardCurveMonthlyAssociatedData.xls.

Figure E-8: Henry Hub Price, Bentek vs. Energy Commission



Source: http://www.benport.com/benport/DisplayReportNews.aspx?LOC=1&ID=0&doc=BENTEK_ForwardCurveMonthlyAssociatedData.xls.

Deloitte's *Navigating a Fractured Future, Insights Into the Future of the North American Natural Gas Market*, 2011

Deloitte Energy Solutions and Deloitte Market Point[76] use their integrated North American and World Gas Model on the MarketBuilder platform to generate a natural gas price forecast. Since Deloitte does not provide specific data in the report, Energy Commission staff estimated the price data points from a graph on page 2 in its report.[77] This means the data estimated for Deloitte will not be exact, preventing an "apples to apples" comparison with the Energy Commission staff's forecast. Besides the reference case, Deloitte also generated the Grand Slam for Gas and the Low Shale Costs cases.

76 http://www.deloitte.com/assets/Dcom-UnitedStates/Local Assets/Documents/Energy_us_er/us_er_Navigatingafractured uture_DCES_250711.pdf.

77 Ibíd.

Deloitte's Assumptions

Reference Case

Deloitte's reference case assumes:

- Continued economic recovery from the recent recession; high demand in North America and worldwide, especially in China and India.
- World demand for natural gas grows at a yearly rate of 1.9 percent, fastest in Asia and the Middle East, above 3 percent per year.
- United States natural gas demand will be driven almost entirely by the electricity sector; demand from other sectors is flat. Overall average annual demand growth is 1.3 percent.

Grand Slam for Gas Case

This case assumes:

- Natural gas demand grows more rapidly, especially in China, up to 16 Bcf/d greater in 2030 than in Deloitte's Reference Case.
- The nuclear disaster in Japan will shut down 60 percent of its nuclear capability, which approximates 30.5 GW, which will be replaced by gas-fired generation, leading to more than 6 Bcf/d in incremental gas demand in Japan by 2030.
- Nuclear power plants in Europe would be replaced by additional gas-fired generation, leading to about 1.5 Bcf/d in incremental gas demand.
- In the United States, the lack of new nuclear plants causes gas demand to increase by about 10 Bcf/d in 2030.
- World gas demand increases up to 466 Bcf/d by 2030.

Lower Shale Costs Case

Some of the key assumptions for this case pertain to shale gas development:

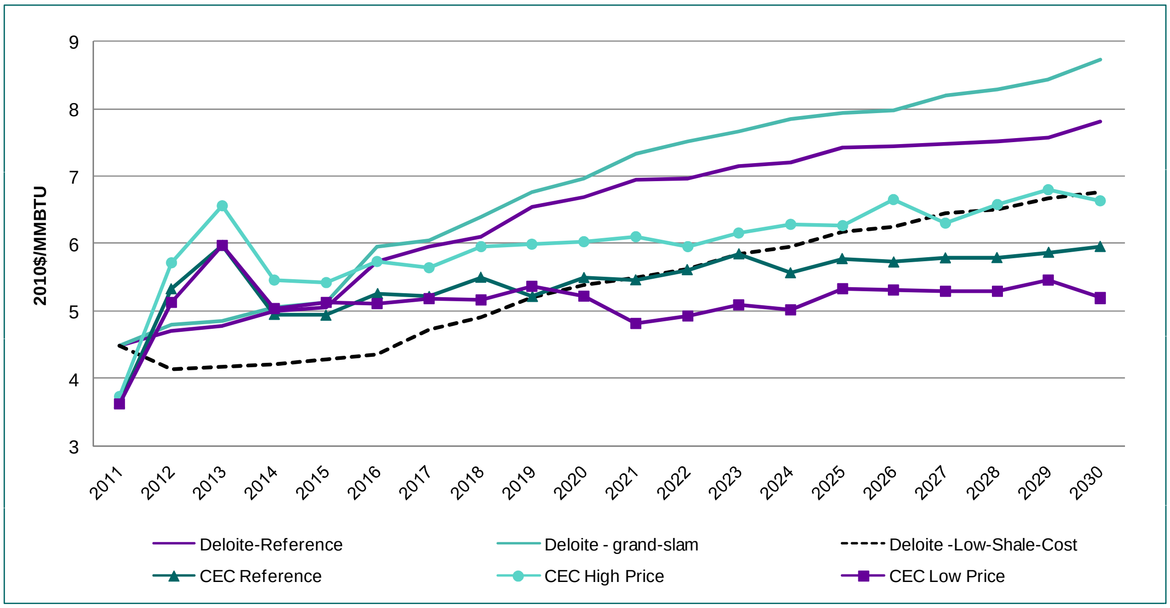
- The costs required finding and producing shale gas is reduced by almost 50 percent.
- The mid-Atlantic market in the United States becomes heavily dependent on shale gas production, especially from the Marcellus shale.

Comparison to Staff Forecast

Figure E-9 compares the Deloitte price forecasts to the Energy Commission staff analysis. The Deloitte forecasts appear to be higher overall and have a slightly wider range between cases than the Energy Commission staff's forecasts. In 2030, the range between Deloitte's Grand Slam and Lower Shale Cost cases is $1.96/MMBtu while the Energy Commission staff price range between the High Price and the Low Price is $1.45/MMBtu, keeping in mind that Deloitte price numbers are estimated from the price graph.

Deloitte's forecast does not show the price jump from 2011 – 2013 that the Energy Commission forecasts do. This may reflect its assumptions on their shale gas supply curves.

Figure E-9: Henry Hub Price, Deloitte Forecast vs. Energy Commission Staff Forecast



Source: [http://www.deloitte.com/assets/Dcom-UnitedStates/Local Assets/Documents/Energy_us_er/us_er_Navigatingafractured uture_DCES_250711.pdf](http://www.deloitte.com/assets/Dcom-UnitedStates/Local%20Assets/Documents/Energy_us_er/us_er_Navigatingafractured%20uture_DCES_250711.pdf).

APPENDIX F: Staff Response to Public Comments

Chapter 5 discusses six new sensitivity cases staff conducted in response to comments made by parties at the September 27, 2011, workshop on the August 2011 staff draft report, *Natural Gas Market Assessment: Outlook*,[78] or in subsequent written comments. Technical comments from parties that are not addressed by these sensitivity cases are discussed in this appendix. Where parties directed staff to alternative natural gas price forecasts, these are discussed in Appendix E.

Usefulness of the Staff's Natural Gas Market Assessment

Filed comment from Mr. Frank Brandt, September 20, 2011:

> *I don't believe* [the **Outlook** report] *is of any real usefulness to the recipients in CA. I repeat that the utilities in CA will have to pay whatever the market price for natural gas is and this will be passed on to the ratepayers. They have absolutely no control. They can ponder the cost but the report doesn't help a bit.*

Staff Response:

> The issue Mr. Brandt raises is fundamental. Since the beginning of the Natural Gas Market Assessment process, staff has acknowledged the fact that making accurate predictions of future natural gas prices is infeasible. This is a necessary consequence of the gas market's high complexity, large menu of competing options for actions, and deep uncertainties about future conditions, which are beyond one's control. The purpose of this report is to provide multiple plausible conditional estimates that explore potential vulnerabilities or opportunities California may face.
>
> Staff specifically designed the assessment to be useful for some purposes, even in the face of this inherent uncertainty. The uncertainty is not infinite: The assessment attempts to identify a plausible range of future prices and the underlying conditions that might lead to them. Nor are utilities and energy policy makers helplessly exposed to future gas price risk. They have options (for example, hedging gas procurement or implementing gas demand reduction policies) to help manage that exposure: The assessment attempts to provide information useful in making these choices more robust. These choices must be informed by some kind of assessment of what future gas market conditions could be like.
>
> Building and running models to understand better the potential effect of the uncertainties on market outcomes thus can be very useful in helping to advise the

78 Publication CEC-200-2011-011-SD.

decision-making. This necessarily implies that some combination of scenario or sensitivity analysis would be useful, and that is the approach staff took in this assessment. Having multiple plausible conditional estimates of the future, which help explore what future natural gas market conditions might be, gives the potential user of such estimates more information about the conditional nature of the estimates to help the user understand the potential consequences of one's own use of a given estimate should the future turn out to be different. Having a better understanding of the uncertainties and their potential consequences can lead to more "robust" decisions — those having satisfactory consequences over a broad range of future conditions that can't be accurately predicted or controlled.

Commissioner Peterman's opening statement at the September 27, 2011, workshop on the staff draft *Natural Gas Market Assessment: Outlook* acknowledges the issue and endorses staff's approach.

> COMMISSIONER PETERMAN: I will say, though, that despite the ability of anyone to accurately predict natural gas prices or gas market outcomes, people like myself and the Chair and Commissioner Douglas ***still need to make decisions based on some expectation of what those outcomes might be***, which is why we put these forecasts together.
>
> I encourage, and I believe staff is committed to using these models to develop insights, rather than simply quantitative results, and we can use these insights and our quantitative results to compare to other scenarios that are out there, other results that are out there, and most importantly to evaluate alternative scenarios or a future using different sets of assumptions. I think what staff has done in this regard has been useful and I look forward to hearing your feedback. [Workshop transcript, pages 9 – 10.]

Throughout the scoping, design, and execution of staff's Natural Gas Market Assessment, other parties have both acknowledged the issue and endorsed staff's approach, a sample of which is:

> Pacific Gas and Electric Company ("PG&E") appreciates the opportunity to provide comments on the California Energy Commission's ("CEC") Draft Staff Report *2011 Natural Gas Market Assessment: Outlook.* PG&E agrees with the staff's acknowledgement that it is impossible to predict the precise state of the world at some future date and that a set of scenarios that provides various views of the future is helpful to understanding the impact of an array of outcomes on the price of natural gas. [PG&E October 11, 2011, comments, page 1.]

Transparency of Staff's Assumptions and Methods

Filed comment from Manuel Alvarez, Southern California Edison, October 11, 2011:

> *SCE suggests that the Draft Report include an appendix with the macroeconomic parameters and values of other drivers in the reference case and the scenario cases. Providing a list of values for all the variables will help stakeholders to better understand the market prices and flow trends resulting from this analysis.*

Staff Response:

> Staff agrees with Edison that transparency helps stakeholders better apply their critical scrutiny to the assumptions, methods, and results of staff's assessment. Staff has given a high priority to explaining the assessment's overall design, assumption building, and execution. However, staff's assessment makes heavy use of the consulting expertise of Dr. Kenneth Medlock, III, of Rice University. The consulting contract guarantees Dr. Medlock some protection of his intellectual property. Therefore, staff cannot unilaterally reveal input assumptions, algorithms, and methods provided this protection. Parties can contact Dr. Medlock directly to request additional disclosure at medlock@rice.edu .

Reasonableness of "Narrow" Range of Gas Prices Across Cases

Filed comment from Valerie Winn, Pacific Gas and Electric, October 11, 2011:

> *At the September 27 workshop, one of the key areas of discussion was the tight range of the CEC's long-term natural gas forecast, with prices ranging from $5 to $7 per MMBtu in 2010 dollars, and demand ranging from 27 to 29 Tcf for the year 2030. Other industry forecasts, including the Energy Information Administration (EIA), show a much larger price range ($4 to $8 per MMBtu) and demand variation (25-32 Tcf) for the same year. While several scenarios were evaluated, one would expect that the range of forecasts would diverge more than is currently expected by the CEC. Therefore, additional analysis is needed to determine whether the narrower forecast range is a reasonable expectation for the future.*

E-mail comment from Jacqueline Jones, Southern California Edison, September 26, 2011:

> *The range over which the prices vary among "High Price" and "Low Price" and reference cases, for each year, is very narrow. For example, for 2020, the reference price for SoCal is $6.35, the "low" price is $5.97 and the high price is $6.90. This narrow range does not represent the way market has behaved in recent past.*

Filed comment from Manuel Alvarez, Southern California Edison, October 11, 2011:

> *The resource supply curve is very flat up to around 600 trillion cubic feet ("Tcf"). To address a high price environment, one assumption could be to reduce the amount of available*

resources along this region of the supply curve. Changes in operational costs and environmental impacts affect not only the cost but also the quantity of gas that can be produced. This will raise the curve upwards to reflect the higher costs and also shift the curve left to account for decreased supplies that can be produced at a given cost. In the current scenarios, the more expensive resource was trimmed off but the quantity and cost of the 'low hanging fruit' remained the same (large enough to not affect the low priced supplies) in both the cases, possibly maintaining the narrow band over the forecast horizon.

Staff Response:

Other parties made similar comments at the workshop. In response, staff developed the sensitivity cases discussed in Chapter 5.

Increasing Amount of Coal-Fired Power Plant Capacity Assumed to Be Retired

E-mail comment from Valiere Winn of PG&E, October 18, 2011:

My team indicated that the total coal generating capacity without scrubbers is about 110 GW. We expect if a CO_2 price is enacted in the US, around 80-90 GW of that capacity would convert to natural gas. Therefore, it would probably be reasonable to assume something more toward the top of the range to capture the scenario extremes.

Staff Response:

Staff's Reference Case input assumptions about power generation gas demand include no significant amount of coal-fired generation converting to natural gas. In staff's High Gas Price Gas Case, 50 GW of coal conversion to gas is assumed, among other changes to Reference Case assumptions. In response to PG&E's suggestion, staff created a new sensitivity case (Sensitivity Case VI, Chapter 5) to examine the incremental effect of increasing coal-fired to natural gas-fired generating capacity conversions from 50 GW to 90 GW. PG&E staff assisted in developing assumptions to geographically distribute the incremental 40 GW of capacity retirements.

How much coal-fired generation capacity actually converts to natural gas is a function of the implementation of a CO_2 price, the expectations about the magnitude of that price, the expectations about future gas prices (which should increase the more coal capacity converts to natural gas), the availability of other options to mitigate CO_2 price risk of coal generation, and the competitiveness of non-gas replacements to coal generation.

Additional Sensitivities to Test Impacts of Changing Variables

Filed comment from Manuel Alvarez, Southern California Edison, October 11, 2011:

> *SCE believes that the total number of scenarios is sufficient, but would like to see the Energy Commission publish the results of any sensitivities that were performed to test the variables used in the scenarios. This information would support understanding the impacts of each variable and their influence in the scenario results.*

Staff Response:

> In general, staff's approach was to construct alternative cases in which more than one variable was changed from the Reference Case value. The exception is the Constrained Shale Gas Case, which is a single variable sensitivity on the impacts of changing the assumption about the environmental mitigation component of operations and maintenance costs. With the six new post-workshop sensitivity cases now in Chapter 5, staff has addressed Edison's comment to some extent, at least for the following variables: F&D capital cost environment, environmental mitigation component of operations and maintenance costs, and coal-fired generating capacity retirements. Although staff agrees such studies provide useful information, given staffing and time constraints, it was impracticable for staff to create single variable sensitivity cases for all variables.

Run-Up in Gas Prices From 2011 to 2012; Run-Down From 2012 to 2013

E-mail comment from Jacqueline Jones, Southern California Edison, September 26, 2011:

> *Please explain what is contributing to the significant increase (50%) in hub prices from 2011 to 2012. This seems to be too high.*

Filed comment from Manuel Alvarez, Southern California Edison, October 11, 2011:

> *Given current market conditions, the significant increase in Henry Hub prices (nearly 50%) from 2011 to 2012 seems unreasonable.*

Staff Response (the following text has been added to Chapter 3):

> To fully understand the model's series of price results, an explanation of the early years of the simulation is helpful. The model begins computing results in the year 2005, using historical data for some key drivers up through 2008 to 2010, depending on the availability of the data. When historical data is not available, assumptions about future conditions are made, generally projecting historical averages into the future. The volatility seen in the model's price results between 2005 and 2010 is in part an artifact of using actual historical data rather than averages of historical data,

which would tend to smooth out results.[79] For example, the 2008 model output shows natural gas prices spiking at over $8.50/MMBtu (in real 2010 dollars). Factors contributing to this result include:

- The model has an econometric component, which contains a crude oil/natural gas price relationship. The historically high oil prices in 2008, which are reflected in the inputs, helped pull up natural gas prices in the model.
- United States hydro generation in 2007 and 2008 was lower than in previous years, increasing natural gas demand by electric generators, where they were the marginal electricity supply.
- United States total electricity generation demand increased in 2007, dropping only slightly in 2008, again affecting gas demand for electric generation natural gas prices.

Similarly, natural gas prices dropped significantly in the 2009 to 2010 portion of this "historical" simulation period, in part due to the effects of the recession which started at the end of 2008 and so reduced the GDP growth assumptions made in the simulation years 2009 and 2010. Another historical input assumption resulting in lower price in the 2009 to 2011 period of the simulation is the growing historical production from unconventional gas resources that were increasing at the time, partially attributable to technological advancements in hydraulic fracturing.

The significant upswing in natural gas prices in 2012 and 2013, when the prices of natural gas jump from the $4/MMBtu range to the $8/MMBtu range, occurs after the simulation period when historical input assumptions are used. So, the shift from historical inputs to input assumptions generally based on historical averages explains some of the upswing. For one, the economy is assumed to be improving, driving up gas demand (and prices, as demand is satisfied at higher levels of the supply curve).[80]

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79 For most of this period, namely 2014 – 2030, prices do not vary much. Many key indicator model inputs assume historical averages or are projected with little to no variation. Three key indicators of interest where averages are assumed: United States hydro generation, United States GDP growth, and United States cooling degree days. United States fossil generation, which is calculated as total electricity production minus United States hydroelectric generation, nuclear generation, and other renewable generation, shows virtually no volatility after 2010 in the Reference Case. This also helps explain the lack of volatility in the model output natural gas prices.

80 Another feature of the modeling which could contribute to the natural gas price drop in 2014 is the release of a constraining assumption in the simulation: the model allows LNG exports from Australia to commence in 2014. For more on Australian LNG exports, see: http://www.arcticgas.gov/Deloitte-forecasts-U.S.-natural-gas-prices-above-$8-by-2022.

Another technical feature of the model is also contributing to rising prices in this early simulation period. The nature of the investment logic in the model can help explain this large price bump in the 2011 – 2013 time period, and the price drop that follows in 2014. The WGTM model uses natural gas production forecasts, based on historical production, for 2005 through 2011. It "accepts" what investments have been made historically in determining the amount of proved gas reserves.[81] and the amount of gas being produced. At this point in the simulation, 2012, the model takes over the internal decisions to "invest" in new natural gas infrastructure in response to increasing demand and the assumed marginal supply curve of gas resources. The investment logic in the model assumes the amount of natural gas production starts at zero in 2012. The model then must prove up natural gas resources to be in line with the historically-based forecast[82]. While the model is proving up these natural gas reserves, through drilling and well development activities, a price surge occurs in 2012 and 2013. In 2014, there is a natural gas price drop of about $1/MMBtu; this is a result of all the natural gas reserves that the model proved up starting in 2012. This is a technical issue with the model that staff is looking into.

Price Elasticity of Demand in a Low-Price Environment

Filed comment from Valerie Winn, Pacific Gas and Electric, October 11, 2011:

> *Model parameters and scenario constructs may not reflect potential outcomes. For example, industrial gas demand elasticity could be much larger in a low price environment.*

Staff Response:

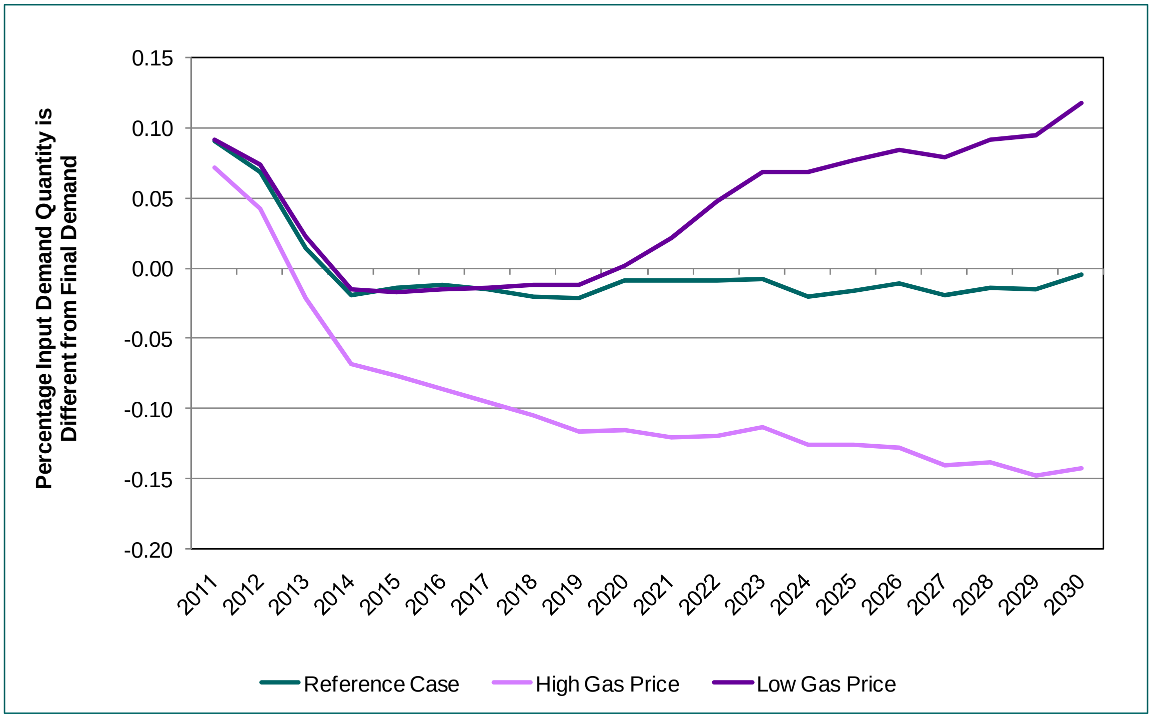
The development of staff's short-term and long-term price elasticity assumptions are discussed at the end of Chapter 2. **Figure F-1** shows the effect of price elasticity of demand assumptions on industrial sector gas demand for the Reference Case and High and Low Gas Price cases. The lines plot the percentage difference between the input (or reference) quantity of demand and the output final equilibrium quantity of demand. For example, industrial sector final equilibrium gas demand in the Low

81 Proved gas reserves refers to the quantities of natural gas that current analysis of geologic and engineering data demonstrate with reasonable certainty (normally 90 percent or greater) to be recoverable in the future from known gas reservoirs under existing economic and operating conditions.

82 "Proving-up" natural gas reserves is the process of expending capital dollars to convert probable and possible reserves (located in the earth's subsurface) into proved reserves. In the WGTM, the investment logic simulates this phenomenon.

Gas Price Case the Price is almost 12 percent higher by 2030 than that case's reference quantity of demand.

Figure F-1: Effect of Price Elasticity on Industrial Gas Demand (Excludes Electric Generation Gas Demand)



Source: California Energy Commission staff analysis.

Since staff's price elasticity assumptions are based on observed price and demand behavior, a future that looks very much different than the past could very well have price elasticity relationships that differ from staff's assumptions.[83] The potential impacts of such a structural change could be explored with additional sensitivity analyses using a plausible range of price elasticity assumptions.

83 For example, chemical or fertilizer manufacturing demand for natural gas as a feedstock could be revitalized under conditions of stable, moderately priced gas.

Capturing Price Effects of Changing Demand

Filed comment from Manuel Alvarez, Southern California Edison, October 11, 2011:

> *The California high and low demand scenarios will not significantly change the model's results for several reasons. First, changing assumptions in California demand do not strongly influence the Henry Hub or overall United States prices and flows. Capacity assumptions for pipelines entering California do influence prices, but only to a limited extent due to the assumption of average annual flows in the Rice Model. Second, the Rice Model does not capture monthly variation or seasonal influence, which is essential to capturing the price effects of changing demand assumptions in the State. For example, removing 20% of the State's generation capacity would affect prices in summer months more than in winter months.*

Staff Response:

> Staff agrees that changing California gas demand does not have much effect on gas price. The High and Low CA Gas Demand cases were designed to examine the range of exposure to overall cost of gas (prices times quantity), GHG emissions, and potential GHG allowance costs. Staff also agrees with Edison's observations about the likely seasonal effect on prices of changes to in-state gas demand.

Providing Monthly Pricing Profile in Addition to Annual Average Prices

E-mail comment from Jairam Gopal, Southern California Edison, October 2011:

> *CEC should do a monthly forecast as that is relevant to what we, the utilities, use. If I were to put a monthly shape to your prices, then it is no longer the CEC price forecast. Hence CEC must develop the monthly shapes or do a fundamental monthly forecast.*

Staff Response:

> Staff ran the WGTM in annual mode only, so there are no seasonal or monthly gas price results. With input from parties, staff could develop a "typical monthly shape" from observed past patterns of actual average monthly prices, or from futures forecasts, and apply that shape to the WGTM's annual average price output from any of the study cases. If interested in participating in such an effort, contact Paul Deaver at paul.deaver@energy.ca.gov.

Significance of Pressure Reduction Case Results

Filed comment from Manuel Alvarez, Southern California Edison, October 11, 2011:

> *The significance of the pressure reduction scenario is limited because pressure reduction largely affects daily operations, which are influenced by storage operations to a large extent. For instance, if storage inventory is high, the pressure reduction and consequent lower flows on pipelines will be complemented by stored gas. Therefore, the modeling exercise without the influence of storage and seasonal variations does not add value to the final conclusions.*

Staff Response:

> Staff agrees that running the WGTM on an average annual basis does not contribute significantly to the discussion of pipeline operational integrity issues. Staff augmented the WGTM run with an additional simplified seasonal analysis. More comprehensive gas flow analyses would provide the most useful information about questions related to future pipeline operations.

Clarifying Trading Hub Nomenclature

E-mail comment from Jacqueline Jones, Southern California Edison, September 26, 2011:

> *Please clarify what "Hub: US-SoCalGas" refers to. Is that SoCal Border, SoCal Citygate, or SoCal Burnertip? If it's the SoCal Border, the spread seems to be too high compare to the SoCal border points. If it's either SoCal Citygate or Burnertip, please explain how these prices are developed.*

Staff Response:

> The WGTM produces natural gas prices for the Henry Hub, California border locations, and citygate locations inside California. The California citygate locations of interest are the PG&E citygate (Hub: US-PG&E), the SoCal Gas citygate location (Hub: US-SoCalGas), and the SDG&E citygate price location (Hub: US-SDG&E). These citygate locations are a direct output of the model and do not require any post-processing. Also, it is important to note that the citygate prices from the model have transportation costs included (up to the citygate location). End-use prices of natural gas are calculated outside the model and are discussed in Chapter 4. Even though they are WGTM results, citygate prices are saved for Chapter 4 because they are the starting point for many of the end-use natural gas price calculations.

Change in Topock Basis Results in High and Low CA Demand Cases

E-mail comment from Jacqueline Jones, Southern California Edison, September 26, 2011:

> *It is hard to believe that the "High CA Demand" scenario, which has the nuclear power generation out and significant increase in gas demand, causes the Topock basis to go. The reference case suggests 28.2 cents for the Topock basis, while the high-demand case has 13.6 cents and low-demand case has 25.1 cents.*

Filed comment from Paul Y'Bardo, Transwestern Pipeline Company, September 27, 2011:

> *Basis differential assumptions are not clear nor is the methodology used in calculating future basis differentials for Topock and Malin. The report's Reference Case projects a price differential between the California Border at Topock and Malin of $0.36/MMBtu (S2010) in the year 2022. Currently, prices in the forward market indicate Topock $0.18/MMBtu higher for October 2011 and $0.14/MMBtu higher for the one year period beginning November 2011.*

Staff Response:

> Staff calculated the basis differential by subtracting the Henry Hub price from the point-of-interest price. After convergence, the model produces resulting prices at all the major trading hubs. Staff simply took the resulting price at the hub of interest and subtracted the Henry Hub price from it to produce a basis differential.
>
> There are several factors that would cause more natural gas to be delivered at the Malin hub at a cheaper price when compared to the Topock/Needle hub. There is price competition from two pipelines (Ruby and GTN) at the Malin hub that will exert downward pressure on natural gas prices. The cheaper sourced natural gas will find its way into California at the Malin hub. The Ruby and the GTN pipelines both draw natural gas from the burgeoning supply plays of the western Canadian sedimentary basin and the Rockies respectively. The Ruby and the GTN pipelines cross minimal demand points en route to California. In fact, the GTN has recently had more free delivery capacity for California given that increased hydro electricity production has displaced much need for natural gas in the Northwest.
>
> Natural gas that arrives at Topock has to cross many more demand points than natural gas that arrives at Malin. The San Juan basin tends to set the price for natural gas delivered on the Transwestern pipeline and has less estimated resource and much more demand placed upon it from the east when compared to plays in Western Canada and the Rockies. This provides more upward price pressure when compared to natural delivered at Malin.

Ruby Pipeline Expansion Assumed Operational in Reference Case

E-mail comment from, Jacqueline Jones, Southern California Edison, September 26, 2011:

> *In calculating the pipeline expansion, is Ruby factored in as one of the expansion pipelines?*

Staff Response:

> The Ruby Pipeline is assumed to be constructed and operational in all cases.

Potential for "Solar-to-Steam" to Reduce Thermal Enhanced Oil Recovery (TEOR) Gas Demand

Filed Comment of Arthur Haubenstock, BrightSource Energy, October 11, 2011:

> *The Energy Commission's data shows that, historically, California TEOR has taken up between 12% and 22% of the entire state's natural gas consumption. Natural Gas Report, in Figure 19, shows the projected impact of the six basic scenarios on TEOR, indicating how basic pricing, demand and supply factors can be expected to affect TEOR natural gas usage. However, the report does not examine the potential for displacement of natural gas for TEOR by solar thermal- derived steam ("Solar-to-Steam"). Solar-to-Steam technology has the potential to substantially reduce the quantity of natural gas used for TEOR over the time period addressed by the study.*

Staff Response:

> Although staff's assessment does not look specifically at this source of uncertainty about future natural gas demand, the potential effect falls within the broad range of demand levels staff did address.

Pipeline Utilization Rates

Filed comment from Paul Y'Bardo, Transwestern Pipeline Company, September 27, 2011:

> *Transwestern Pipeline currently has a utilization percentage of 98% for its West of Thoreau segment. The report's Reference Case projects a utilization of 37 percent in the year 2022. Such a dramatic reduction in utilization requires a thorough examination of the drivers behind it.*

Staff Response:

> The Transwestern Pipeline segment used for the utilization rate calculation was aggregated into a pipeline corridor within the model with two other interstate pipelines—EPNG and Mojave pipelines. Staff cannot produce a utilization rate for the Transwestern pipeline alone, given the way the model is currently structured.

The utilization rate was calculated at the point where the aggregated pipeline corridor connects to the Topock/Needles hub. This means that only gas that is delivered to California was used in the utilization rate calculation. The utilization rate may appear low at first glance because the effective delivery capacity for the aggregated corridor was not used in the utilization rate calculation. But rather, the aggregated nameplate capacities of the three pipelines were used when staff calculated the utilization rate for the pipeline corridor. The number that will not change regardless of the method of utilization rate calculation (delivery capacity vs. nameplate capacity) is the flow number that reaches Topock. Staff believes that this is real issue that is being questioned here. Reasons supporting the amount of flow we expect to arrive at Topock can be read below.

Pipeline-Specific Variable Transportation Cost Assumptions

Filed comment from Paul Y'Bardo, Transwestern Pipeline Company, September 27, 2011:

Variable transportation cost assumptions across various pipelines are not specified. Gas prices in the supply basin and variable transportation costs will determine which pipelines are utilized. Transwestern Pipeline currently has very competitive variable transportation costs and recently filed to reduce the fuel charge for shippers transporting to California from the San Juan supply area.

Staff Response:

Transwestern pipeline is represented within a pipeline corridor in the model. This corridor is the combination of Transwestern, EPNG North, and Mojave pipelines. The transportation rate for this corridor is as follows: 0.33$/Mcf in 2010, 0.38$/Mcf in 2015, 0.41$/Mcf in 2020, and 0.45$/Mcf in 2025.

Representation of Transwestern's Pipeline Network

Filed comment from Paul Y'Bardo, Transwestern Pipeline Company, September 27, 2011:

Transwestern Pipeline has greater supply diversity than noted in the report. Transwestern is connected not only to supply in the San Juan basin but it can also access the Permian, Rockies via TransColorado and Northwest, Mid-continent, and Texas shale supply areas.

Staff Response:

The pipeline corridor (which contains Transwestern, EPNG North, and Mojave pipelines) is connected, in the WGTM model, to the San Juan basin, Permian, Rockies, Mid Continent, and Texas Shale supply areas.

APPENDIX G:
Price Forecasts and Gross Domestic Product Deflator Series

Table G-1: Gross Domestic Product Deflator Series

Year	1977=1	2005=1	2007=1	2010=1
1970	64.42	24.32	22.88	21.98
1971	67.64	25.53	24.02	23.08
1972	70.55	26.63	25.06	24.07
1973	74.47	28.11	26.45	25.41
1974	81.23	30.66	28.85	27.71
1975	88.90	33.56	31.57	30.33
1976	94.01	35.49	33.39	32.07
1977	100.00	37.75	35.51	34.12
1978	107.02	40.40	38.01	36.51
1979	115.92	43.76	41.17	39.55
1980	126.49	47.75	44.92	43.15
1981	138.34	52.23	49.13	47.20
1982	146.78	55.41	52.13	50.08
1983	152.59	57.60	54.19	52.06
1984	158.32	59.77	56.23	54.01
1985	163.11	61.58	57.93	55.65
1986	166.71	62.94	59.21	56.88
1987	171.55	64.76	60.93	58.53
1988	177.45	66.99	63.02	60.54
1989	184.15	69.52	65.40	62.82
1990	191.25	72.20	67.92	65.25
1991	198.03	74.76	70.33	67.56
1992	202.73	76.53	72.00	69.16
1993	207.21	78.22	73.59	70.69
1994	211.57	79.87	75.14	72.18
1995	215.98	81.54	76.71	73.69
1996	220.09	83.09	78.17	75.09
1997	223.98	84.56	79.55	76.41

Table G-1: Gross Domestic Product Deflator Series (Continued)

Year	1977=1	2005=1	2007=1	2010=1
1998	226.51	85.51	80.45	77.28
1999	229.84	86.77	81.63	78.41
2000	234.82	88.65	83.40	80.11
2001	240.12	90.65	85.28	81.92
2002	244.01	92.12	86.66	83.25
2003	249.27	94.10	88.53	85.04
2004	256.34	96.77	91.04	87.45
2005	264.89	100.00	94.08	90.37
2006	273.52	103.26	97.14	93.32
2007	281.57	106.30	100.00	96.06
2008	287.72	108.62	102.19	98.16
2009	290.36	109.61	103.12	99.06
2010	293.11	110.65	104.10	100.00
2011	295.41	111.52	104.91	100.78
2012	301.05	113.65	106.92	102.71
2013	309.23	116.74	109.82	105.50
2014	316.14	119.35	112.28	107.86
2015	322.32	121.68	114.47	109.96
2016	328.45	123.99	116.65	112.06
2017	334.02	126.09	118.63	113.95
2018	339.13	128.03	120.44	115.70
2019	344.12	129.91	122.21	117.40
2020	349.07	131.78	123.97	119.09
2021	354.14	133.69	125.77	120.82
2022	359.34	135.65	127.62	122.59

Source: California Energy Commission *Staff 2011 Preliminary California Energy Demand (CED) Forecast*.

Table G-2: Index to Convert $2010 to Nominal $ (2010=100)

Year	Index
2005	90.37
2006	93.32
2007	96.06
2008	98.16
2009	99.06
2010	100.00
2011	100.78
2012	102.71
2013	105.50
2014	107.86
2015	109.96
2016	112.06
2017	113.95
2018	115.70
2019	117.40
2020	119.09
2021	120.82
2022	122.59
2023	124.45
2024	126.32
2025	128.23
2026	130.17
2027	132.13
2028	134.13
2029	136.15
2030	138.21

Note: California Energy Commission deflator series extends only to 2022. Index beyond 2022 assumes same growth rate as the 5-year average from 2017-2022.

Table G-3: Original Cases Annual Average Spot Market Prices of Natural Gas at Henry Hub, $2010/MMBtu

Year	Reference Case	High Gas Price	Low Gas Price	Constrained Shale	High CA Demand	Low CA Demand
2005	7.01	7.25	7.01	7.26	7.01	7.01
2006	5.70	5.83	5.70	5.85	5.70	5.70
2007	6.68	6.63	6.68	6.66	6.68	6.68
2008	8.90	8.56	8.93	8.63	8.69	8.77
2009	3.33	3.47	3.33	3.55	3.36	3.34
2010	3.63	3.70	3.62	3.69	3.63	3.64
2011	3.65	3.75	3.64	3.79	3.63	3.63
2012	5.34	5.74	5.14	5.29	5.13	5.41
2013	5.99	6.58	5.98	6.31	5.89	5.87
2014	4.96	5.47	5.05	5.27	4.94	4.90
2015	4.95	5.44	5.14	5.15	4.90	4.96
2016	5.27	5.74	5.13	5.35	5.32	5.09
2017	5.23	5.65	5.19	5.52	5.34	5.36
2018	5.51	5.97	5.18	5.72	5.59	5.65
2019	5.23	6.01	5.38	5.90	5.56	5.42
2020	5.51	6.04	5.23	5.76	5.57	5.51
2021	5.47	6.12	4.83	5.84	5.50	5.49
2022	5.63	5.98	4.94	5.96	5.66	5.49
2023	5.86	6.17	5.11	5.91	5.69	5.54
2024	5.58	6.30	5.03	5.75	5.54	5.33
2025	5.79	6.28	5.34	5.72	5.67	5.72
2026	5.74	6.66	5.32	5.75	5.67	5.68
2027	5.80	6.33	5.30	5.90	5.74	5.80
2028	5.80	6.60	5.31	5.93	5.80	5.79
2029	5.88	6.81	5.46	6.15	6.11	5.97
2030	5.97	6.65	5.20	6.21	6.03	5.91
Avg 2014-22	5.31	5.82	5.12	5.61	5.38	5.32
Avg 2023-30	5.80	6.47	5.26	5.92	5.78	5.72

Source: California Energy Commission staff analysis.

Table G-4: Original Cases Annual Average Spot Market Prices of Natural Gas at Henry Hub, Nominal $/MMBtu

Year	Reference Case	High Gas Price	Low Gas Price	Constrained Shale	High CA Demand	Low CA Demand
2005	6.34	6.55	6.34	6.56	6.34	6.34
2006	5.32	5.44	5.32	5.46	5.32	5.32
2007	6.42	6.37	6.42	6.40	6.42	6.42
2008	8.74	8.40	8.77	8.47	8.53	8.61
2009	3.30	3.44	3.30	3.52	3.33	3.31
2010	3.63	3.70	3.62	3.69	3.63	3.64
2011	3.68	3.78	3.67	3.82	3.66	3.66
2012	5.49	5.89	5.28	5.44	5.27	5.55
2013	6.32	6.94	6.31	6.66	6.21	6.20
2014	5.35	5.90	5.45	5.68	5.33	5.29
2015	5.44	5.98	5.65	5.66	5.39	5.46
2016	5.91	6.44	5.74	6.00	5.96	5.70
2017	5.96	6.44	5.91	6.29	6.09	6.11
2018	6.38	6.90	5.99	6.62	6.47	6.53
2019	6.14	7.06	6.32	6.93	6.53	6.36
2020	6.56	7.20	6.23	6.86	6.63	6.57
2021	6.61	7.39	5.84	7.06	6.64	6.63
2022	6.90	7.33	6.05	7.30	6.94	6.73
2023	7.29	7.68	6.36	7.35	7.09	6.89
2024	7.05	7.96	6.35	7.27	7.00	6.74
2025	7.42	8.05	6.85	7.34	7.27	7.33
2026	7.47	8.67	6.93	7.48	7.38	7.39
2027	7.67	8.36	7.00	7.80	7.58	7.67
2028	7.79	8.85	7.12	7.96	7.79	7.77
2029	8.01	9.28	7.44	8.37	8.32	8.12
2030	8.25	9.18	7.19	8.58	8.33	8.17
Avg 2014-22	6.14	6.74	5.91	6.49	6.22	6.15
Avg 2023-30	7.62	8.50	6.90	7.77	7.59	7.51

Source: California Energy Commission staff analysis

Table G-5: Sensitivity Cases Annual Average Spot Market Prices of Natural Gas at Henry Hub, $2010/MMBtu

Year	Reference Case	Sensitivity I - Ref Case With High F&D Costs	Sensitivity II - Ref Case With Low F&D Costs	Sensitivity III - Low Gas Price Case With Low F&D Costs	Sensitivity IV - High Gas Price Case With High F&D Costs	Sensitivity V - Sens IV With Additional $0.30/McfRef O&M	Sensitivity VI - Sens V With Additional 40 GW Coal Conversion
2005	7.01	7.01	7.01	7.01	7.25	7.32	7.32
2006	5.70	5.70	5.70	5.70	5.83	5.94	5.94
2007	6.68	6.68	6.68	6.68	6.63	6.78	6.78
2008	8.90	8.75	8.74	8.72	8.68	8.53	8.60
2009	3.33	3.35	3.36	3.34	3.47	3.59	3.58
2010	3.63	3.63	3.63	3.64	3.69	3.86	3.86
2011	3.65	3.64	3.66	3.68	3.76	3.92	3.91
2012	5.34	6.17	4.47	5.12	6.40	6.22	6.15
2013	5.99	7.61	4.80	5.46	7.84	7.92	8.05
2014	4.96	5.98	4.18	4.18	6.43	6.86	6.73
2015	4.95	5.81	4.34	4.04	6.56	6.33	6.64
2016	5.27	6.23	4.48	4.12	6.47	6.84	6.89
2017	5.23	6.16	4.54	4.42	6.75	6.71	6.79
2018	5.51	6.43	4.88	4.53	6.66	7.06	6.89
2019	5.23	6.59	4.72	4.65	7.08	7.04	7.23
2020	5.51	6.36	4.71	4.20	6.89	7.03	6.98
2021	5.47	6.69	4.78	4.43	6.92	7.37	7.40
2022	5.63	6.62	4.67	4.47	7.13	7.21	7.13
2023	5.86	6.57	4.85	4.70	7.06	7.39	7.37
2024	5.58	6.72	4.94	4.47	7.29	7.35	7.31
2025	5.79	6.65	5.03	4.28	7.33	7.22	7.22
2026	5.74	6.68	4.93	4.46	7.31	7.66	7.32
2027	5.80	6.75	5.01	4.64	7.22	7.40	7.30
2028	5.80	7.03	5.09	4.63	7.36	7.76	7.70
2029	5.88	7.04	5.14	4.51	7.53	7.63	7.90
2030	5.97	7.07	5.38	4.37	7.54	7.63	7.67
Avg 2014-22	5.31	6.32	4.59	4.34	6.77	6.94	6.97
Avg 2023-30	5.80	6.82	5.05	4.51	7.33	7.51	7.48

Source: California Energy Commission staff analysis.

Table G-6: Sensitivity Cases Annual Average Spot Market Prices of Natural Gas at Henry Hub, Nominal $/MMBtu

Year	Reference Case	Sensitivity I - Ref Case With High F&D Costs	Sensitivity II - Ref Case With Low F&D Costs	Sensitivity III - Low Gas Price Case With Low F&D Costs	Sensitivity IV - High Gas Price Case With High F&D Costs	Sensitivity V - Sens IV With Additional $0.30/McfRef O&M	Sensitivity VI - Sens V With Additional 40 GW Coal Conversion
2005	6.34	6.34	6.34	6.34	6.55	6.61	6.61
2006	5.32	5.32	5.32	5.32	5.44	5.54	5.54
2007	6.42	6.42	6.42	6.42	6.37	6.51	6.51
2008	8.74	8.59	8.58	8.56	8.53	8.38	8.44
2009	3.30	3.32	3.32	3.31	3.43	3.55	3.55
2010	3.63	3.63	3.63	3.64	3.69	3.86	3.86
2011	3.68	3.67	3.69	3.71	3.79	3.95	3.94
2012	5.49	6.34	4.59	5.26	6.57	6.39	6.32
2013	6.32	8.02	5.06	5.76	8.27	8.36	8.49
2014	5.35	6.45	4.51	4.51	6.93	7.40	7.26
2015	5.44	6.39	4.77	4.44	7.21	6.96	7.31
2016	5.91	6.98	5.02	4.62	7.26	7.66	7.72
2017	5.96	7.02	5.18	5.04	7.69	7.65	7.74
2018	6.38	7.44	5.64	5.24	7.70	8.17	7.97
2019	6.14	7.74	5.54	5.46	8.31	8.26	8.49
2020	6.56	7.57	5.61	5.00	8.21	8.38	8.31
2021	6.61	8.08	5.77	5.35	8.36	8.91	8.94
2022	6.90	8.12	5.72	5.48	8.75	8.84	8.74
2023	7.29	8.18	6.04	5.84	8.78	9.20	9.18
2024	7.05	8.50	6.24	5.64	9.21	9.28	9.24
2025	7.42	8.53	6.46	5.48	9.40	9.26	9.26
2026	7.47	8.70	6.41	5.80	9.52	9.97	9.53
2027	7.67	8.92	6.62	6.13	9.54	9.78	9.65
2028	7.79	9.43	6.83	6.21	9.88	10.41	10.33
2029	8.01	9.58	7.00	6.15	10.25	10.39	10.76
2030	8.25	9.78	7.44	6.04	10.42	10.55	10.60
Avg 2014-22	6.14	7.31	5.31	5.02	7.82	8.03	8.05
Avg 2023-30	7.62	8.95	6.63	5.91	9.63	9.86	9.82

Source: California Energy Commission staff analysis.